CASE: UE 319
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Opening Testimony
Redacted

June 16, 2017

Q. Please state your name, occupation, and business address.

A. My name is Marianne Gardner. I am a Senior Requirement Analyst employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/401.

Q. What is the purpose of your testimony?

A. I am the revenue requirements summary witness for the Public Utility Commission of Oregon Staff (Staff) in this proceeding. I introduce Staff-sponsored adjustments and issues regarding Portland General Electric's (PGE or Company) filing in this docket, identified as UE 319. As such, I verify PGE's proposed revenue requirement utilizing Staff's revenue requirement model. This model is also used to calculate Staff's modified revenue requirement after incorporating Staff's proposed adjustments to PGE's revenue requirement.

Additionally, I provide background regarding specific issues I reviewed, my analysis, and my recommendations.

Q. Will other Staff witnesses submit testimony regarding the issues they reviewed?

A. Yes. Each Staff assigned to Docket UE 319 is submitting separate testimony. In Part 1 of my testimony, I introduce the Staff witnesses and their respective assignments, and estimate the revenue requirement impact of Staff's recommended adjustments to the Company's initial filing. These are the issues identified to date. Staff's recommendations and issues may change after reviewing testimony and analysis by other parties.

Q. Did you prepare exhibits for this docket?

A. Yes. I prepared the following exhibits:

Exhibit 401	Witness Qualification Statement
Exhibit 402	Uncollectibles –
Exhibit 403	Wages, Salaries and Incentives –
Exhibit 404	Escalation – Excerpt from Consumer Price Index – All Urban Consumers for the U.S., published by OEA (released November 16, 2016)
Exhibit 405	Company Responses to Staff Data Requests DR Nos. 288, 644, 294, 295, 296, 309, 430, 429, 407, 312, 313, 469, 470, 94, 92, and 425 and ICNU DR No. 48.
Exhibit 406	Company Confidential Responses to Staff DR Nos. 68, 469 and ICNU DR No. 48.

Q. How is your testimony organized?

A. My testimony is organized as follows:

PART 1: Revenue Requirement

Q. **Please provide a list of the rate case topics that Staff reviewed and introduce the responsible Staff.**

A. I have provided a listing of rate topics and adjustment amounts.

			Company filed incremental revenue requirement	**$99,896**
	Staff	**Item**	**Proposed Staff Adjustments**	**Revenue Requirement Effect**
400	Marianne Gardner	S-1.1	**Uncollectible Rate**	**(18)**
400	Marianne Gardner	S-1.2	**Uncollectibles**	**(497)**
400	Marianne Gardner	S-2.1	**OPUC Fees Rate**	**(49)**
400	Marianne Gardner	S-2.2	**OPUC Fees**	**(1,385)**
400	Marianne Gardner	S-3	**Interest Synchronization**	**4,261**
400	Marianne Gardner	S-4	**Amortization & Cyber Security**	**(6,378)**
400	Marianne Gardner	S-5	**Income Taxes and ADIT (placeholder)**	**0**
400	Marianne Gardner	S-6	**Working Cash - Incremental rounding in model**	**(5)**
400	Marianne Gardner	S-7	**Level III Storm accrual**	**414**
400	Marianne Gardner	S-8	**Escalation**	**(1,697)**
400	Marianne Gardner	S-9	**Wages, Salaries, Overtime,FTE,CET Benefits, Incremental FTE Benefits**	**(23,241)**
400	Marianne Gardner	S-10	**Insurance**	**(520)**
400	Marianne Gardner	S-11	**Medical and Other Benefits**	**0**
400	Marianne Gardner	S-12	**Distribution O&M (placeholder)**	**0**
500	Matt Muldoon	S-13	**Cost of Capital**	**(36,040)**
500	Matt Muldoon	S-14	**Pensions (placeholder)**	**0**
500	Matt Muldoon	S-15	**AFUDC (placeholder)**	**0**

600	Phil Boyle	S-16	**Fee Free Bankcard**	**(666)**
700	Lance Kaufman	S-17	**Residential Sales**	**(15,521)**
700	Lance Kaufman	S-18	**Other Revenue**	**(2,985)**
700	Lance Kaufman	S-19	**Carty**	**(2,344)**
700	Lance Kaufman	S-20	**MMA**	**(793)**
700	Lance Kaufman	S-21	**Generation O&M**	**(93)**
700	Lance Kaufman	S-22	**Affiliated Interests (placeholder)**	**0**
800	Scott Gibbens	S-23	**Customer Service**	**(1,225)**
800	Scott Gibbens	S-24	**Environmental Licensing**	**(1,118)**
900	Kathy Zarate	S-25	**R&D (adjusted), Advertising, Promotional Activities, Dues & Memberships**	**(932)**
1000	Ming Peng	S-26	**Depreciation (placeholder for adjustments to net plant)**	**0**
1100	Moore	S-27	**Plant in Service**	**(7)**
1100	Moore	S-28	**CET Deferral & amortization (placeholder for amortization)**	**0**
1300	Max St. Brown	S-29	**Legal Fees (placeholder)**	**0**
1300	Max St. Brown	S-30	**Low Connection Services**	**(1,857)**
1300	Max St. Brown	S-31	**Non-residential Load Forecast**	**(10,416)**
1400	George Compton	S-32	**Optional Residential Schedule Pricing**	**0**
1500	JP Batmale	S-33	**Energy Efficiencies/Energy Trust**	**0**
			Total Staff-Proposed Adjustments (Base Rates):	**($103,112)**
			Staff-Calculated Revenue Requirements Change (Base Rates):	**($3,216)**

PART 2: SPECIFIC ISSUES

Q. What areas of PGE's filing are you primarily responsible for reviewing?

A. I reviewed the portions of the filing related to:

- Uncollectible Rate and Uncollectible Expense,
- Taxes other than Income,
- Interest Synchronization,
- Amortization Expense and Accumulated Amortization Expense,
- State Income Tax (SIT), Federal Income Tax (FIT), Accumulated Deferred Income Taxes (ADIT),
- Working Capital,
- Major Storm Damage Accrual,
- Salaries, Wages and Incentives,
- Non-medical Insurance,
- Employee Medical Benefits, and
- Materials and Supplies in Rate Base.

In order to gain additional insight, I reviewed the Company's responses related to Staff's standard Data Requests (SDRs), issued approximately 53 additional DRs, and reviewed the Company's responses.

ISSUE 1. Uncollectible Rate and Uncollectible Expense

Q. Please provide a summary of the Commission's historical treatment of uncollectible expense, the Company's filed proposal, and Staff's analysis of the issue.

A. It is a long-standing policy of the Commission Staff to apply a three-year average methodology to determine the test year uncollectible expense for a utility's revenue requirement.[1] However, Commission Staff also examines other evidence to determine whether this approach results in a reasonable forecasted test year result.

In this case, the Company proposes a 0.370 percent uncollectible rate on light and power retail revenue. This is based on a five-year average of actual write-offs for the calendar years 2012-2016. The Company has chosen a five-year average because the Company believes it better reflects economic cycles and normalizes significant one-time events.[2] For example, the Company points to its plan to suspend some credit and collection activities when it implements its new Customer Information System. The suspension may result in a higher uncollectible rate for 2018.[3]

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[1] *See, e.g.*, *In the Matter of Avista Corporation*, OPUC Docket UG 246, Order No. 14-015 at 3(January 21, 2014) and *In the Matter of Avista Corporation*, OPUC Docket UG 186, Order No. 09-422, Appendix A at 4 (October 26, 2009) (adopting stipulations for Avista general rate increase with uncollectible expense in revenue requirement based on three-year average); *but see In the Matter of Idaho Power Company*, OPUC Docket UE 167, Order No. 05-871 (January 28, 2005) (adopting stipulation for Idaho Power Company general rate increase with uncollectible expense based on four-year average) and In the Matter of Cascade Natural Gas Corporation, OPUC Docket UG 287, Order No. 15-412 (December 28, 2015) (adopting stipulation for Cascade Natural Gas general rate increase with uncollectible expense based on three-year average, removing an anomalous year).

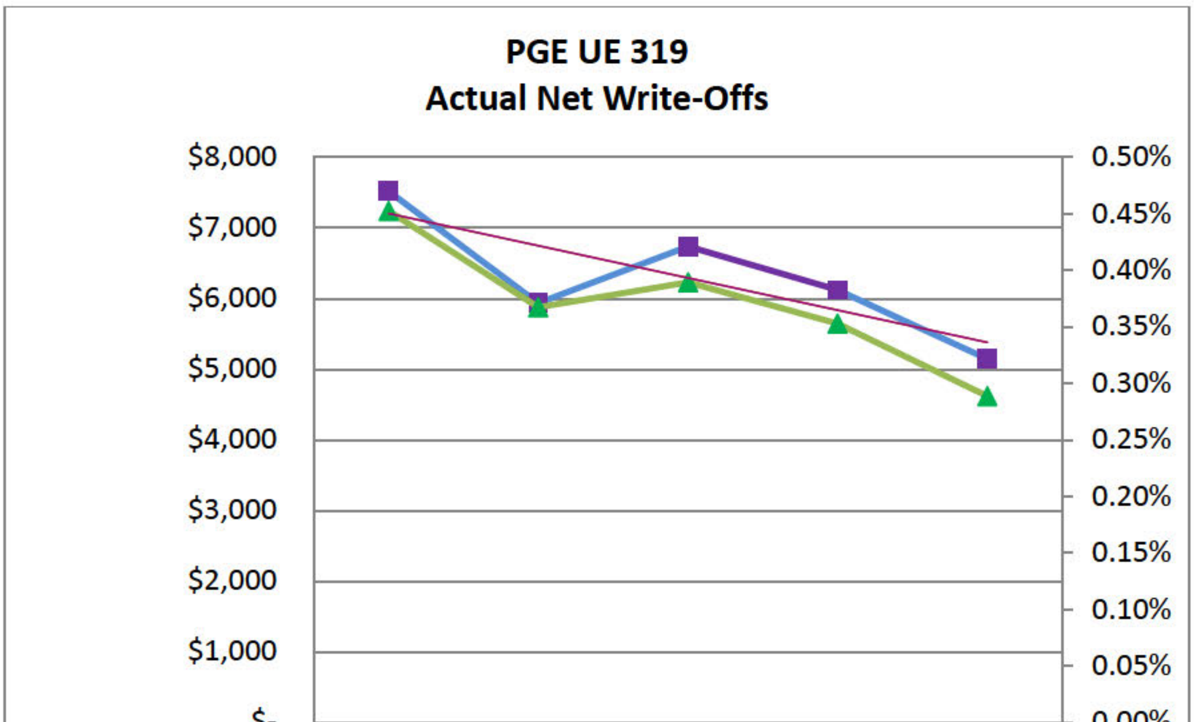
[2] PGE/900, Stathis-Dillin/6 at 9-12.

[3] Ibid/6 at 4-21.

Q. Does Staff agree with PGE's proposed rate based on a five-year average?

A. No. Staff proposes to use a three-year average of actual write-offs using the data for the calendar years 2014-2016 provided in the Company's response to Staff DR No. 288.[4] As shown in Table 1 below, the uncollectible rate has been steadily trending down for the last five years.

Table 1.[5]



	2012	2013	2014	2015	2016
Net Write-Offs	$7,516	$5,936	$6,736	$6,121	$5,144
% of revenue	0.4525%	0.3673%	0.3894%	0.3529%	0.2886%

The 0.3700 percent rate proposed by the Company is too high. An uncollectible rate of 0.3431 percent, which is the three-year average

[4] Staff/405, Gardner; PGE Response to Staff DR No. 288.
[5] See PGE Workpaper, PGE Work Papers Exh _Uncollectibles.xlsx.

uncollectible rate,[6] better reflects the downward trend in the uncollectible rate. Staff agrees with the Company's testimony that the suspension of the credit and collection activities in 2018 may result in an anomalous uncollectible rate for that year. However, Staff proposes removing an anomalous year's data for a historical year's data that is more representative of normal uncollectible performance.

Q. What is Staff's proposed adjustment for the uncollectible rate and uncollectible expense for the 2018 test year?

A. Staff proposes an uncollectible rate of 0.3431 percent as described above. Because the uncollectible rate is a revenue sensitive rate, Staff proposes applying this rate to the final agreed upon general revenues to calculate the appropriate level of uncollectible expense to be included in the 2018 test year. At this time, based on the Company's proposed general revenues in its Exhibit 201,[7] Staff proposes a decrease to the Company's test year uncollectible expense of ($480,000).[8] Additionally, Staff proposes the 0.3431 percent rate replace PGE's proposed uncollectible rate of 0.3750 in calculating the net to gross factor for the revenue requirement.

[6] See Staff electronic workpaper, UE 319 Uncollectibles S-1 –Gardner.xlsx, tab S-1.1.
[7] UE 319 PGE/201, Tooman – Brown/1.
[8] See Staff electronic work paper, UE 319 Uncollectible S-1 Gardner.xlsx.

ISSUE 2: Taxes Other than Income

Q. Please provide a summary of the Commission's historical treatment of taxes other than income, the Company's filed proposal, and Staff's analysis of the issue.

A. The category "Taxes other than Income" typically includes franchise fees, the regulatory fee imposed by the OPUC, property taxes, payroll taxes and other miscellaneous taxes or fees incurred by the energy utility. Payroll taxes are included as a component of the wages and salaries issue, which is discussed in a subsequent section of this testimony.

Franchise fees, along with business or occupation taxes, licenses, and similar exactions or costs, are allowed as operating expenses for ratemaking purposes on the condition these costs do not exceed 3.5 percent of gross revenues for an electric utility.[9] For simplicity, these costs are referred to collectively as franchise fees. The OPUC fee is also included in operating expenses for ratemaking purposes. In rate cases, franchise fees and the OPUC fee are a function of the fee rate multiplied by gross revenues and are called revenue sensitive costs. Additionally, these revenue sensitive rates are included in the conversion factor in determining the revenue requirement. Historically, the franchise fee rate has been based on a three-year average. Property taxes related to property that is not yet used and useful may not be included in customer rates of an electric utility.[10] Hence, these property taxes

[9] See OAR 860-022-0040(1).
[10] See ORS 727.355(1).

are excluded from the rate case operating expenses. Property taxes related to property that is used and useful are included in rate case operating expense and are usually forecasted for ratemaking purposes based on historical property tax information.

The Company's 2018 test year proposal for franchise fees and OPUC fees is $47.9 million and $7.062 million,[11] respectively. The corresponding rates for the franchise fee and the OPUC fee are 2.5455 percent and 0.3750 percent, respectively.[12] The Company's 2018 test year proposal for property taxes is $60.7 million composed of taxes levied by Oregon, Montana and Washington for PGE property owned in these states.[13] Included in the rate case are the taxes related to Oregon jurisdictional utility operations.

Q. Does Staff find the Company's proposed franchise fee rate reasonable?

A. Yes. Based on Staff's analysis, Staff finds the franchise fee rate to be reasonable. Staff reviewed the franchise fee rate calculation included in the Company's filed workpapers, issued a few clarifying DRs and discussed the calculation with PGE.

Q. Does Staff find the Company's proposed OPUC Fees rate reasonable?

A. No. According to Order 17-065, the most recent OPUC order setting the annual fee rate, the rate is set at 0.30 percent. This is the maximum rate the

[11] See PGE Workpaper, Exhibit Support.xlsx, tab RevReq –Base, cells D33 and D24.
[12] UE 319/PGE/201, Tooman-Brown/3.
[13] UE 319/PGE/206, Tooman-Brown/1.

Commission is allowed to assess utilities.[14] In PGE's Exhibit 201, the Company's proposed OPUC Fees rate is 0.3750 percent.[15] Staff reviewed the electronic version included in the Company's excel workbook, Exhibit Support 2018.xlsx, tab Ex 201 ROO-Cap, and found the underlying computation to be 0.3 percent multiplied by 1.25 percent. Staff issued DR No. 644 asking PGE to explain why it has grossed up the 0.3 percent rate by 1.25. In its response, the Company explained the gross up of the 0.3 percent rate was incorrect as it was based on a prior assumption regarding retail revenue and wholesale revenue levels that no longer holds true.[16] The Company now proposes a rate of 0.3211 percent, which is based on an alternate calculation that averages the most recent three years of actual data.[17] This calculation grosses up the 0.30 percent OPUC Fee in relation to sales for resale that are under the 25 percent threshold of total revenues as defined in ORS 756.310(3). Staff is conducting additional discovery regarding the gross-up. According to the Company's Exhibit 201, sales for resales are not included in the base business operating revenues. Therefore, Staff is unclear how the Company has accounted for sales for resales and the related OPUC fees in the test year base rates. Staff is concerned these sales and the related OPUC fees may be netted in Net Variable Power Cost.[18]

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[14] See ORS 756.310(3).
[15] UE 319/PGE/201, Tooman-Brown/3.
[16] Staff/405, Gardner, PGE Response to Staff DR No. 644.
[17] Ibid.
[18] PGE/201, Tooman-Brown/1.

Q. What is Staff's recommendation?

A. Because the OPUC fee rate is a revenue sensitive rate, Staff proposes applying the most current rate of 0.30 percent levied by the Commission to the final general revenues ordered by the Commission to calculate the appropriate level of OPUC fees to be included in the 2018 test year. At this time, based on the Company's proposed general revenues in its Exhibit 201,[19] Staff proposes a decrease to the Company's OPUC fee expense of ($1.388) million.[20] Additionally, Staff proposes to replace Company's revenue sensitive rate of 0.3750[21] with Staff's proposed 0.30 percent rate in calculating the net to gross factor for the revenue requirement.

Q. Does Staff find the Company's proposed property tax amount for the 2018 test year reasonable?

A. Yes. Staff finds the 2018 test year property tax expense to be reasonable in relation to the amount of net plant proposed for the test year. In DR No. 476, Staff requested the Company's property tax data for the years 2008 -2016. Staff compared the amount of tax accrued against the net book value of the property and finds that the ratio of the 2018 test year property tax to 2018 proposed net plant is consistent. For the 2018 test period, the Company net plant and property tax are $5,143.348 million and $60.743 million, respectively. Ratioing these values yields a percentage of 1.181 percent.

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[19] Ibid.
[20] See Staff electronic work paper, UE 319 OPUC Fee S-2 Gardner.xlsx.
[21] PGE/201, Tooman-Brown/3.

Q. Please summarize Staff's recommendation regarding property tax expense.

A. I recommend adjusting property tax to reflect the final net plant supported by Staff.

ISSUE 3: Interest Synchronization

Q. Please provide a summary of the Commission's historical treatment of interest synchronization, the Company's filed proposal, and Staff's analysis of the issue.

A. According to long-standing Commission policy, for ratemaking purposes, Staff routinely synchronizes interest expense to reflect changes in the regulated utility's cost of capital as initially filed in a general rate case. This is consistent with the treatment in PGE's last general rate case, UE 294. The interest synchronization adjustment depends on Staff Witness Matt Muldoon's proposed adjustments to cost of capital (CoC) in this docket. Mr. Muldoon has recommended in his testimony an adjustment to the Company's filed cost of capital, of which the weighted cost of debt is a component. Because interest expense on long-term debt is tax deductible, Mr. Muldoon's proposed cost of long-term debt impacts income tax expense for ratemaking purposes. The cost of long-term debt proposed in PGE's direct testimony is 5.170 percent.[22] Staff, as supported by Mr. Muldoon's testimony, recommends a 4.852 percent cost of debt and a weighted cost of long-term debt of 2.450 percent.[23]

Q. What is Staff's recommendation?

A. As the Revenue Requirement Summary witness, I recommend synchronizing the interest expense for the income tax calculation to reflect a weighted cost of debt of 2.450 percent. Based on the Company's test year rate base of

[22] PGE/201, Tooman-Brown/3.
[23] Staff/500, Muldoon/2.

$4,594,052 and weighted cost of long-term debt of 2.585 percent,[24] Staff proposes to reduce interest expense by $6,190,000 = ($4,954,052*(2.585% - 2.450%)).

The amount is calculated on the test year as follows:

+ Net Rate Base

X Staff's Recommended (or Authorized) Weighted Cost of Debt

= Allowable Interest Deduction

- Company's Reported Interest Deduction

= Interest Coordination Adjustment

This adjustment can be found in Staff workpaper, UE 319 Interest Synchronization S-3 MG.xlsx.

[24] Ibid.

ISSUE 4: Amortization Expense and Accumulated Amortization Expense

Q. Please provide a summary of the Commission's historical treatment of amortization expense and accumulated amortization, the Company's filed proposal, and Staff's analysis of the issue.

A. Historically, the Commission has authorized straight-line amortization of intangibles. Intangibles are generally comprised of computer software, licenses, and regulatory assets and liabilities. Amortization expense for the test year is charged to cost of service and the net asset is included in rate base (Intangible asset less accumulated amortization equals net plant).

In UE 319, the Company calculated the 2018 test year amortization based on the 2017 adjusted annualized amortization. The total amortization expense requested is $68.3 million.[25] The Company's proposed software amortization expense comprises 69 percent of the total request, or $47 million.[26] PGE amortizes capitalized software primarily over a five-year period, or a 20 percent rate.[27] However, the completed projects of the 2020 Vision program are amortized over a ten-year period, or a 10.0 percent rate.[28] I verified with Ming Peng, OPUC Senior Economist, that the rates and the accumulated amortization amounts are correct.

[25] UE 319/PGE/204, Tooman-Brown/1.
[26] UE 319/PGE/200, Tooman – Brown/8 at 10.
[27] Staff Exhibit/ 405, Gardner, PGE Response to Staff DR No. 294.
[28] Ibid.

Q. Please explain any additional analysis Staff undertook to verify the underlying projects that are subject to amortization.

A. In Staff DR No. 294, Staff requested an amortization schedule listing all intangible projects that comprise the 2018 test year amortization. According to the Company's response, the amount of amortization for 2017 software additions is $9.6 million, or 20.5 percent of the total software amortization expense.[29] Staff shared this project listing with other Staff reviewing new plant additions. I also inquired of the Company regarding preliminary costs otherwise known as start-up costs included in the 2018 test year.[30]

Q. Why did Staff inquire about 2018 start-costs?

A. In past rate cases, Staff has recommended amortizing significant start-up costs for software projects in order to smooth the costs in customer rates.[31] For GAAP purposes, these costs are expensed. According to PGE's response to Staff DR No. 295, PGE's accounting treatment of these costs is consistent with GAAP.[32]

Q. What type of information did the Company provide regarding start-up costs?

A. In the Company's response to Staff DR No. 296, the Company explained that it tracks costs separately for large projects like the Customer Engagement

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[29] Ibid.
[30] Ibid.
[31] See Order No. 13-459, pp. 5 (Docket No. UE 262) (Commission approving stipulation in which parties agreed to treat development costs as regulatory asset with a five-year amortization).
[32] Staff Exhibit/405, Gardner, PGE Response to Staff DR No. 295.

Transformation (CET) project but not for all IT projects.[33] The Company, in its response to DR 309, provided the allocated IT O&M costs in account 1840004, by accounting work orders (AWO) for the years 2014 - 2018. The actuals were provided for the years 2014-2016, and the budgeted and forecasted amounts were provided for 2017 and 2018, respectively.[34] For the 2018 test year, the Company did not track any projects in the accounting system in the manner the CET was tracked. In reviewing the Company's excel workbook, OPUC_DR_309_Attach A.xlsx, Staff notes that the Company has forecasted for AWO 3000001006 - Cyber Security Roadmap, a total of $7,701,211 in IT O&M costs. Of the 353 individual AWOs, this one AWO is significant as it represents 36 percent of the total allocated IT O&M cost.

Q. What is Staff's recommendation?

A. Staff is conducting additional discovery regarding start-up costs. At this time, Staff recommends amortizing the $7,701,211 costs for the Cyber Security Roadmap AWO over five years. This results in an overall decrease in O&M costs of ($6,160,936).

As the Revenue Requirement Summary Witness, I will update the test year amortization expense and reserves to reflect adjustments sponsored by other Staff witnesses to intangible plant. Therefore, while I do not propose any other adjustments to amortization expense or the reserve account other than that proposed for the Cyber Security Roadmap. However, my final adjustment

[33] Staff/405, Gardner, PGE Response to Staff DR No. 296.
[34] Staff/405, Gardner, PGE Response to Staff DR No. 309.

on this issue will change contingent on the final intangible rate base supported by Staff.

ISSUE 5: State Income Tax, Federal Income Tax and Accumulated Deferred Income Tax

Q. Please summarize the applicable requirements for ratemaking treatment of federal income tax (FIT), state income tax (SIT) and accumulated deferred income tax (ADIT).

A. Consistent with Internal Revenue Code (IRC) Sections 168(f)(2) and 168(i)(9) (Normalization Rules for Public Utilities) and ORS 757.269(1), public utilities are required to normalize federal income taxes for revenue requirement purposes. Normalization of federal income taxes means that a regulated public utility that uses accelerated depreciation for tax purposes must record in rate base a related deferral of taxes that arises from the difference between book depreciation and tax depreciation. According to IRC Sec. 168(i)(9)(A):

> In order to use normalization method of accounting with respect to any public utility property for purposes of subsection (f)(2)—
> (i) the taxpayer must, in computing its tax expense for purposes of establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, use a method of depreciation with respect to such property that is the same as, and a depreciation period for such property that is no shorter than, the method and period used to compute its depreciation expense for such purposes; and
> (ii) if the amount allowable as a deduction under this section with respect to such property (respecting all elections made by the taxpayer under this section) differs from the amount that would be allowable as a deduction under section 167 using the method (including the period, first and last year convention, and salvage value) used to compute regulated tax expense under clause (i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Also, ORS 757.269 (1) states "[s]ubject to subsections (2) and (3) of this section, amounts for income taxes included in rates are fair, just and reasonable if the rates include current and deferred income taxes and other related tax items that are based on estimated revenues derived from the regulated operation of the utility." According to subsection (3):

> During a ratemaking proceeding conducted under ORS 757.210 for an electricity or natural gas utility that pays taxes a part of an affiliated group, the Public Utility Commission may adjust the utility's estimated income tax expense based upon: (a) Whether the utility's affiliated group has a history of paying federal or state income taxes that are less than the federal or state income taxes the utility would pay to units of government if it were an Oregon-only regulated utility operation; (b) Whether the corporate structure under which the utility is held affects the taxes paid by the affiliated group; or (c) Any other considerations the commission deems relevant to protect the public interest.

Q. Please summarize PGE's proposed SIT, FIT and ADIT requested in this case.

A. The Company's proposed 2018 test period income tax expense is $159.749 million, composed of $27.459 million in state income tax and $132.291 million in federal income tax. The Company's proposed accumulated deferred income tax is $18.301 million.[35]

Q. Did the Company normalize taxes for federal income tax purposes?

A. The Company did not include a narrative in its testimony specifically addressing the normalization of federal income tax. However, Staff did

[35] PGE/205, Tooman-Brown/1.

confirm, through data requests, that the Accumulated Deferred Federal Income Tax (ADIT) amount of ($634.410) million included in the test year rate base incorporates a depreciation timing difference arising from bonus depreciation as taken by the Company on Federal income tax returns filed as of April 19, 2017, consistent with IRC Section 168(i)9.[36] However, the Company indicated it has elected out of bonus depreciation for the tax years 2012-2015.[37]

Q. Did Staff inquire regarding whether the test year ADIT included bonus depreciation related to 2016 plant additions and 2017 plant additions?

A. Yes. In the Company's response to Staff DR No. 430, the Company explained it did not claim bonus depreciation for the estimated 2016 or 2017 plant additions included in its 2018 test year rate base for the same reasons set forth in the Company's response to Staff DR No. 429.[38] Specifically, PGE stated that there is a potential to lose permanent Oregon tax credit benefits if not taken before they expire. Also, the federal Domestic Production Activity Deduction is reduced or eliminated by increased tax deprecation. Electing bonus depreciation may defer the tax benefit of the federal Production Tax Credit (PTC) giving rise to a deferred tax asset in rate base. Finally, the Company poses that unknown future tax code changes may eliminate PGE's ability to utilize deferred PTCs.

[36] Staff/405, Gardner, PGE Response to Staff DR No. 430.
[37] Ibid.
[38] Ibid.

Q. What is the impact of PTCs in UE 319?

A. The Company stated in testimony that part of the increase in income tax expense, as compared to 2016 taxes versus 2018 test year of $74.1 million and $159.7 million, respectively, reflects "federal production tax credits (PTC) being treated as a variable, rather than fixed, component of PGE's forecast, consistent with the provisions of Oregon Senate Bill 1547, section 18b." The Company started treating the PTC as a variable component in its UE 308 2017 Net Variable Power Cost (NVPC) proceeding. [39]

Q. Did the Company offset income tax expense in the 2018 test year with estimated generated PTCs or include any deferred PTCs as an asset in rate base?

A. Staff is conducting additional discovery with regards to how PGE incorporated PTCs in this rate case. Since this docket includes the NVPC adjustment, Staff is unclear regarding how the Company included the variable component in UE 319.

Q. What is Staff's recommendation?

A. Staff does not recommend an adjustment to income tax expense, ADIT, or deferred tax credits at this time. Staff has issued an additional data request and is reviewing PGE's responses to other parties' tax related data requests. Staff will update its recommendation, as appropriate, in its rebuttal testimony.

[39] UE 319/PGE/200, Tooman-Brown/10 at 1-12.

ISSUE 6: Working Capital

Q. Please provide a summary of the Commission's historical treatment of working capital (working cash) in rate base, the Company's filed proposal, and Staff's analysis of the issue.

A. The Commission historically allows electric utilities to include working capital in rate base.[40] Working capital is estimated based on a working capital factor calculated by a recent lead lag study. In this rate case, the Company included $56.833 million of working capital in rate base calculated by multiplying the test year total operating expenses of $1,566.5 million by a 3.628 percent working cash factor.[41]

Q. Did Staff request additional information regarding the working cash factor and the Company's lead lag study?

A. Yes. The Company did not provide any testimony or workpapers in its initial filed case. Therefore in Staff DR No. 407, Staff requested the Company provide background regarding the rate, whether it was still relevant, and whether new programs or software programs have had any impact on the working cash factor.[42] In the Company's response, it stated that this is the same rate used in its last general rate case, UE 294.[43] Although the Company did update its lead lag model in third quarter of 2016, the Company explained that because the 3.789 percent rate was not significantly different from the

[40] Order No. 16-076 at Appendix A, p. 3 (UG 288).
[41] UE 319 / PGE/200, Tooman – Brown/14 at 16-19.
[42] Staff/405, Gardner, PGE Response to Staff DR No. 407.
[43] Ibid.

3.628 percent utilized in UE 294, the Company decided to use the UE 294 rate of 3.628 percent and present an updated lead lag study in its next general rate case.[44] The Company also explained that the Fee Free Bankcard program has not impacted its revenue collection as evidenced by its days sales outstanding (DSO) for the years 2013-2016.[45] Additionally, the Company commented that Maximo, while it has improved work order tracking, has not improved lead lag times associated with the inventory.[46]

Q. Based on Staff's review is the Company's proposed 2018 working cash factor of 3.628 percent appropriate for this docket?

A. Yes.

Q. What is Staff's recommendation?

A. Staff recommends keeping the cash working cash factor of 3.628 percent for this docket, and recommends that a new or updated lead lag study be submitted by PGE in its next general rate case.

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[44] Ibid.
[45] Ibid.
[46] Ibid.

ISSUE 7: Major Storm Damage Accrual

Q. Please provide a summary of the Commission's historical treatment of PGE's Major Storm Damage Accrual.

A. PGE currently collects $2 million annually in rates for use against future Level III storm costs.[47] To the extent that amounts are not used in a given year, the funds are maintained to offset costs related to Level III storms in future years.[48] Stipulating parties in Docket No. UE 215 agreed on a rolling ten-year average, adjusted to present value.[49]

Q. What is PGE's proposal for rate recovery related to Level III storms in this case?

A. PGE makes two proposals related to rate recovery for Level III storms in this case. First, PGE proposes to increase the accrual rate from $2 million to $2.6 million based on the current 10-year rolling average.[50]

Second, the Company proposes a change in accounting treatment that would allow the balance of the account to become negative when annual Type III storm damage costs exceed the annual accrual.[51]

Q. How did the Company incorporate the proposed annual accrual of $2.600 million into its proposed 2018 revenue requirement?

A. During a discussion regarding the accrual with the Company, Staff learned that the Company did not actually incorporate the additional $600,000

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[47] PGE/800, Nicholson-Bekkedahl/26.
[48] Ibid.
[49] Ibid.
[50] Ibid.
[51] Ibid.

requested in testimony in its test year revenue requirement. In reviewing the Company's proposed adjustments to the 2018 test year, it was noted that the Company included in distribution expense the $2,000,000 accrual that is currently allowed in base rates.[52]

Q. Regardless of this error, did Staff analyze PGE's proposal to increase the annual storm accrual to $2.6 million?

A. Yes. Staff prepared three scenarios using the data provided in PGE's Exhibit 804. Because the Level III storm accrual is constructed on a 10-year rolling average, Staff modeled the data as if the annual accrual had existed for each of the years 2007-2016. Staff escalated the ten-year total to 2018 dollars using the CPI, Urban Consumers.[53] In Scenario 1 Staff found that if the storm accrual of $2 million had been in place since 2007, Level III storm costs would have been $4.296 million greater than what was recovered in rates in 2018 dollars. In Scenario 2, Staff assumed PGE's proposed $2.6 million was the annual accrual in place for the years 2007-2016. If this were the case, the Company would have over-recovered Level III storm costs by $2.386 million stated in 2018 dollars. In Scenario 3, Staff calculated the results assuming an annual accrual of $2.4 million for the years 2007-2016. This resulted in $151,691 in over-recovery as escalated to 2018 dollars.[54] Since Scenario 3

[52] See the Company's Excel workpaper filed in conjunction with its initial filing, Exhibit Support.xlsx, tab Distribution, line 30.
[53] Staff/402, Gardner/8.
[54] See Staff electronic work paper, UE 319 Storm Deferral S-7 Gardner.

results in a net recovery that is closest to zero, Staff believes setting the annual accrual at $2.4 million will result in fair and just rates.

Q. What is Staff's recommendation with regard to the increase in annual accrual amounts?

A. Staff recommends the Commission include an increase to the $2,000,000 annual accrual currently in base rates. However, Staff believes the Company's proposed amount of $2.600 million is too high and recommends, at this time, that the accrual be increased by $400,000 for a total of $2.4 million since this results in a net recovery that is closest to zero according Staff's analysis above.

Q. Why is the Company proposing the change in accounting treatment for Level III storm costs?

A. In its testimony, PGE presented an analysis of the storm accrual versus its incurred storm costs. From the inception of the storm accrual in 2011 through 2015, the Company accrued $10 million.[55] However, this balance was reduced to zero due to large storms in 2014 and 2015.[56] Therefore, there was no accrued balance available to cover the 2016 storm costs, which were $2.5 million in excess of the $2 million annual accrual.[57] In its Exhibit 804, the Company presented a rolling 10-year average analyzing storm costs starting with 1995 and ending with a preliminary estimate of the 2017 January storms. Based on this analysis, PGE concluded that a negative balance would be the

[55] PGE/800, Nicholson-Bekkedahl/26.
[56] PGE/800, Nicholson-Bekkedahl/26-27.
[57] PGE/800, Nicholson-Bekkedahl/27.

norm because clusters of calm winters are followed by clusters of stormy winters.[58] According to PGE, these stormy winters will drive the accrual balance negative because the amount accrued in the calm winters will not offset the stormy winters' costs.[59] PGE also concludes there is a minimum two-year lag from when storms occur and when PGE can incorporate the negative impact in a general rate case.[60]

In support of its proposed accounting treatment, PGE argues that this treatment, whereby the balance can fluctuate between negative and positive, is similar to treatment currently allowed for its major maintenance accruals (MMAs).[61] The Company's viewpoint is that utilizing the same accounting treatment as the MMA would smooth cost recovery for the Company from customers.[62] The Company believes the current recovery method for Level III storms creates a need for a higher reserve and annual collection from customers in rates to cover costs incurred during cycles of severe storms.[63]

Q. Did Staff request additional information regarding storm costs?

A. Yes. Staff DR No. 312 requested the criteria for designation as a Level III storm and whether any of the 2016 storms resulted in capital expenditures. In the Company's response, it provided the following criteria for Level III storm costs:

- Multiple substations and feeders out of service;

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[58] PGE/800, Nicholson-Bekkedahl/27-28.
[59] PGE/800, Nicholson-Bekkedahl/27.
[60] Ibid, 27-28.
[61] Ibid, 28 -29.
[62] PGE/800, Nicholson-Bekkedahl/29.
[63] PGE/800, Nicholson-Bekkedahl/28.

- Greater than 50,000 customers out of service;
- Three or four regions are experiencing outages;
- Greater than 72 hours to restore service; or
- Outside assistance may be required.[64]

Additionally, the Company explained in response to Staff DR No. 313, "[w]hen PGE determines that restoration costs are covered by the storm reserve, however, certain costs are excluded from the reserve account (e.g., straight time labor and associated labor loadings) because they are already included in base rates.[65] As stated in PGE's response to OPUC Data Request No. 312, any capital-related storm restoration costs are also excluded from the reserve account."[66] Staff's discovery of storm costs is ongoing. Staff issued DR Nos. 646-649 requesting further information regarding capitalization, insurance proceeds, and non-Level III storm costs, but will not have the Company's responses to these data requests prior to the filing of Staff's opening testimony.

Q. Does Staff agree with the Company's proposal that the current accounting for Level III storm cost be changed to mirror the accounting for MMAs?

A. No. MMA costs are covered under a maintenance contract and while they vary due to the maintenance schedule, costs are based on output.[67] PGE's trend analysis of Level III storms does not constitute scientific proof of severe storm patterns in and around Portland, Oregon. Also, as a matter of policy, Staff does not concur with shifting weather-related risk to ratepayers from

[64] Staff/405, Gardner, PGE Response to Staff DR No. 312.
[65] Staff/405, Gardner, PGE Response to Staff DR No. 313.
[66] Staff/405, Gardner.
[67] See Staff/700, Kaufman/23.

shareholders. Between rate cases, utilities generally bear the risk of weather impacts on operating and maintaining their systems.[68] Allowing the account to go negative would allow PGE to obtain dollar-for-dollar recovery of Level III storm costs, which represents a shift in risk from shareholders to ratepayers. Staff views Level III storm costs as a stochastic risk, meaning that the risk can be predicted as part of the normal course of events.[69] For these types of risks, Staff does not believe that extraordinary ratemaking treatment is warranted, particularly in light of the fact that PGE may file for a deferral pursuant to ORS 757.259 if costs from a particular storm are significant.

Q. What is Staff's recommendation regarding the PGE's proposed accounting treatment?

Staff recommends the Commission reject the Company's proposal to change the Level III storm accounting to mirror the accounting used for MMA. Staff believes, the monies accrued and expended should continue to be accounted for as they are currently. As in this rate case, if the actual Level III storm costs exceed the annual accrual in base rates, the Company may request the Commission increase the annual accrual in a future general rate case.

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[68] *See* Order 04-108, 8-11.
[69] Ibid.

ISSUE 8: Escalation

Q. Please summarize Staff's policy for escalation.

A. It is Staff policy to use the Consumer Price Index – All Urban Consumers for the U.S. (CPI, Urban U.S.) as published by the State of Oregon Office of Economic Analysis (OEA) for year over year escalation of expenses. The most recent release was the May 2017 report, released May 16, 2017. According to Appendix A of this report, the percentage change for CPI for 2015 to 2016, 2016 to 2017, and 2017 to 2018 is 1.3 percent, 2.5 percent, and 2.4 percent, respectively.[70] Staff used these last three percentages. According to PGE's testimony, the Company escalated the 2017 budgeted expenses for certain cost elements to arrive at the filed 2018 test year amount.[71]

Q. What escalation rates did PGE use to escalate its 2017 budget to the 2018 test year?

A. As provided in testimony, the costs and escalators for costs other than compensation are as follows:

- 3.11% for outside services (cost elements [CE] 1502, 1602, 2200, and 2300), effective January 1.
- 1.66% for direct materials (CE 2101 and 2110), effective January 1.
- 2.39% for employee business expense (CE 2400 and 2701), effective January 1.[72]

[70] Staff Exhibit/402, Gardner/8.
[71] PGE/200, Tooman-Brown/3.
[72] Ibid.

Q. Did the Company provide in testimony or the workpapers filed in conjunction with its opening testimony the escalation calculation or the amount included in the 2018 test year?

A. No.

Q. Did Staff issue any data requests to the Company seeking additional detail regarding the Company's escalation adjustment?

A. Yes. Staff issued DR Nos. 469 and 470. In DR No. 469, Staff requested a detailed calculation of the Company's escalation adjustment related to the non-labor portion for the above listed CEs by FERC account. In the Company's response, PGE explained, "these escalation factors are some of the numerous factors creating differences from 2016 to 2018 and are not separable indefinable in PGE's accounting system." [73]

Q. What was Staff's request in Staff DR No. 470?

A. In DR No. 470, Staff requested the Company provide justification of the appropriateness of the escalators, copies of the original source documents that support the Company's position, and the Company's rationale for applying each escalator to particular CE numbers or CE type.[74] The Company referred Staff to its confidential response, OPUC_DR_469_Attach A_CONF.xls, which Staff has included in Confidential Staff Exhibit 406. However, this response did not justify the appropriateness of the escalators nor did it explain the Company's rationale for applying a specific escalator to specific CE numbers or

[73] Staff/405, Gardner, PGE Response to Staff DR No. 470.
[74] Ibid.

types. Additionally, the Company referenced the source document but did not provide the source document.

Q. Does Staff propose an adjustment to the Company's escalation?

A. Yes. Based on the previously discussed inflation factors, Staff recommends a decrease of ($1.639) million to PGE's 2018 test O&M expenses.[75]

[75] See Staff electronic workpaper, UE 319 Escalation S-8 - Gardner, tab S-8.1

ISSUE 9: Salaries, Wages and Incentives

Q. Please provide a summary of the Commission's historical treatment of wages, salaries, incentives, and overtime expense.

A. The Commission typically uses Staff's three-year wage and salary model (W&S model) to estimate expenses for non-union wages and salaries.[76] The increases in payroll from the historic base year should be tied to the rate of inflation using the All-Urban CPI.[77] Rather than using All-Urban CPI for union wages, the Commission in the past has ordered that union payroll increases be tied to negotiated wage increases as set forth in the union contract.[78] Staff applied this model to the information the Company provided in its filing and responses to Staff data requests.

For incentives, Commission policy traditionally disallows 100 percent of officers' bonuses, which are typically based on earnings.[79] It is also Commission policy to disallow 75 percent of performance-based bonuses (because they are generally focused on increased earnings and, therefore, bring more benefit to shareholders) and disallow 50 percent of merit-based

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[76] See e.g., *In the Matter of PacifiCorp*, OPUC Docket UE 116, Order No. 01-787 at 40 (September 7, 2001).

[77] See Order 01-787 at 40; *In the Matter of Northwest Natural*, OPUC Docket UG 132, Order No. 99-697 at 43 (November 12, 1999); *In the Matter of PGE*, OPUC Docket UE 102, Order 99-033 at 61 (January 27, 1999); *In the Matter of PGE*, OPUC Docket UE 88, Order No. 95-322 at10 (March 29, 1995).

[78] See Order No. 99-697 at 43.

[79] See Order No. 99-033 at 62; *In the Matter of the Application of US West*, OPUC Docket UT 125, Order No. 97-171 at 74-76 (May 19, 1997).

bonuses (because they equally benefit shareholders and ratepayers). Union bonuses are treated in the same manner as non-union bonuses.[80]

Q. Please summarize PGE's proposal for wages, salaries, incentives and overtime expense in this case.

A. The Company includes in the test year approximately $272.827 million in wages and salaries, $12.583 million in incentive compensation, and $15.810 million in overtime.[81]

Q. How do the Company's adjustments to salaries, wages and incentives differ from those Staff typically makes in a general rate case?

A. Staff explains the differences by each component of Staff's W&S model below.

Escalation

As explained in its testimony, PGE used a rate of 3.50 percent derived from industry and marketing data to escalate its non-bargaining wages and salaries from its budgeted 2017 year to its 2018 test year. The Company escalated union wages in a similar manner using a rate of 2.54 percent.[82]

Staff, consistent with Staff's W&S model, escalated the 2015 historical year to a projected 2018 using the All-Urban CPI (CPI).[83] For union employees, Staff escalation is based on the last contracted rate increase from 2015 to 2016 of 2 percent as provided by in Company in its response to Staff

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[80] See Order 99-697 at 44-45; Order 99-033 at 62.

[81] These amounts are found in the Company's Excel spreadsheet, Total Compensation.xlsx, filed with Exhibit 400 electronic workpapers.

[82] PGE/400, Mersereau-Jaramillo/15.

[83] Staff/402, Gardner/8.

DR No. 94.[84] In testimony the Company stated, except for the Coyote, Port Westward, and Carty sites, the terms of the union contract are in effect until February 2020.[85] The Coyote, Port Westward, and Carty sites union contracts will expire August 1, 2017.[86] Staff then applied the sharing percentages to Staff's projected 2018 test year amounts. If Staff's projection is less than the Company's test year amount, the sharing test allows the Company to share 50/50 the lesser of the difference between the Company's filed proposal and Staff's calculated projection, or a 10 percent band around Staff's calculated projection.[87]

Q. What is Staff's recommendation regarding the escalation of salaries and wages to include in the 2018 test year?

A. Staff recommends reducing the base year salaries and wages by ($2.962) million allocated as ($2.064) million O&M expense and ($897) million capital.[88]

Incremental FTEs

Q. Please provide the background for this issue.

A. PGE's 2018 test year forecast includes costs of approximately 270 incremental FTEs over PGE's 2016 actual FTE count, [89] which is approximately a ten percent increase in its workforce. Costs of incremental FTEs are a significant driver in PGE's request for a $99 million

[84] Staff/405, Gardner, PGE Response to Staff DR No. 94.
[85] PGE/400, Mersereau-Jaramillo/15.
[86] PGE/400, Mersereau-Jaramillo/16 at 14-18.
[87] See Staff electronic workpaper, UE 319 W&S S-9 - Gardner, tab S-9.1 PUC 3-year W&S.
[88] Ibid.
[89] PGE/400, Mersereau-Jaramillo/11.

increase in revenue requirement. For the reasons that follow, Staff is concerned with the cost of this unprecedented increase in PGE's workforce and the impact to ratepayers. PGE plans to distribute the new FTEs as follows:

- A&G 18.7
- IT 44.2
- Cust Svc/Accts 5.9
- Generation 31.6
- T&D 169.3[90]

Q. Why is Staff concerned about the FTE increase?

A. First, many of the FTEs that PGE says it needs are for new initiatives or to expand existing programs, many of which are discretionary at least with respect to timing. Staff is concerned about PGE's decision to proceed with these initiatives now. This is the fourth rate case since 2012. PGE's rates have gone up to allow cost recovery for significant capital additions. Staff does not think it is appropriate to turn to ratepayers to fund a dramatic increase to PGE's workforce after the multiple increases for other costs.

Q. Why is it significant that many of the incremental FTEs that PGE says it needs are for new initiatives?

A. PGE asserts that it is: (1) deploying and leveraging technology to enhance efficiency and effectiveness, which results in doing more with less over the long term, and (2) reworking processes to improve efficiency, increase customer responsiveness and avoid cost increases through continuous

[90] PGE/400, Mersereau-Jaramillo/12.

improvement.[91] Although these efforts may be targeted at creating efficiencies and avoiding cost increases, these two goals are not achieved in this rate case. Staff's review of the reasons underlying PGE's proposed $99 million revenue requirement increase shows that "reworking processes to improve efficiencies" and "leverag[ing] technology" to enhance efficiency and do more with less over the long-term requires hiring more than 200 employees in the near-term. While Staff appreciates PGE's goals, they have to be balanced with the economic interests of ratepayers. PGE is seeking 5.6 percent average increase, which includes a 7.1 percent increase in residential customer rates.[92]

Staff is concerned that PGE has put little downward pressure on its proposed revenue requirement. PGE states that it attempted to limit the asked-for increase by doing three things: (1) asking for an ROE at the low-end of its range, (2) removing half of the cost of excess layers of D&O insurance, (3) removing 100 percent of officer long-term incentive program costs and 50 percent of incentive compensation costs.[93] These are not meaningful measures. Staff has proposed removal of 50 percent of all D&O insurance in the last several rate cases. The Commission expressly adopted this treatment in one of them when the issue was contested.[94] And, the low-end of PGE's range of acceptable ROEs is still higher than what Staff believes is an

[91] PGE/100, Piro-Lobdell/8.
[92] PGE/100, Piro-Lobdell/8.
[93] PGE/100, Piro-Lobdell/5-6.
[94] Order No. 09-020, pp. 19-20 (Docket No. UE 197).

appropriate ROE.[95] Finally, PGE's proposed treatment of incentives is more favorable to the Company than what Staff generally proposes in rate cases.

Further, PGE's proposed revenue requirement in this case is misleading because a significant amount of costs that PGE is currently incurring for its Customer Engagement Transformation (CET) project and has incurred for its recently constructed Carty plant are not included. PGE will likely ask to include $128 million in capital costs related to the CET Project in its next rate case.[96] And PGE has a pending request to defer the revenue requirement effects of over $200 million of its capital investment in Carty as well as other costs such as legal costs.[97]

Q. What does Staff recommend with respect to PGE's incremental FTEs included in this rate case?

A. Staff believes PGE's cost recovery for new FTEs should be reduced. First, to the extent that PGE plans to hire FTEs to implement new initiatives or expand existing programs; to capitalize on new functionality created by new technology; or to capture efficiencies identified in its internal "continuous improvement cycle" or other internal improvement process, some portion of these initiatives and programs should be paid for by efficiencies and cost-savings rather than through incremental charges to customers. Second, as discussed in the testimony of Staff witnesses Mitch Moore, Lance Kaufman,

[95] See Staff/500, Muldoon/1-2.
[96] PGE/900, Stathis-Dillin/13.
[97] Docket No. UM 1791 (PGE Application for Deferral of Incremental Revenue Requirement Associated with the Carty Generating Station and Delay of Commission Review of PGE's Application until Legal Actions are Resolved) (July 29, 2016).

Max St. Brown, and Rose Anderson, PGE has not adequately justified the need or the need for cost recovery for several of the incremental FTEs.

Q. Is Staff recommending that the Commission disallow costs associated with certain FTEs in order to prevent PGE from implementing certain initiatives?

A. No. Staff has identified initiatives and individual FTEs that Staff believes PGE should or could pay for through cost savings and efficiencies, or that should be delayed until such time they can be implemented without imposing such a burden on ratepayers. Staff recommends that the Commission reduce PGE's proposed test year expense based on its analysis of certain programs and FTEs, but it will then be up to PGE to determine how to spend the revenue requirement that is left.

Q. What FTEs are tied to PGE's implementation of new initiatives?

A. PGE says approximately 22 of the new FTEs needed in its Information Technology (IT) department to implement new initiatives and projects that fall under its "Information Security Roadmap," finalized in 2016. PGE testifies that nine FTEs are needed to develop and staff a new "Integrated Security Operations Center" (ISOC); five FTEs are needed to implement "Identity and Access Management" (IAM), a new initiative to establish, extend, or improve key service capabilities across the enterprise[;]" four FTEs are needed for security testing, third-party risk management, and threat analysis; and two FTEs (one manager, one administrator) are needed to oversee the overall implementation of the roadmap.[98]

Several of the other incremental FTEs to be hired in PGE's IT department are intended to support new initiatives or expanding programs. For example, PGE asserts that it needs two "Business Relationship Management" analysts to help IT to "work closely" with PGE's T&D and Customer Service departments "and know exactly what they need and why[;]" three FTEs to provide support for ongoing infrastructure fitness evaluation, ensure compliance with software license agreements, and ensure an appropriate level of service enterprise wide; four FTEs to provide adequate support to existing and new technologies; four FTEs to provide 24/7 support at data center operations; and two FTEs to support PGE's activities in the Western Energy Imbalance Market.[99]

Many of the 18.7 FTEs that PGE plans to hire for corporate support are also needed to support new initiatives such as centralization of the training department, and centralization of the procurement department.

Similarly, 90 of the T&D FTEs in the 2018 revenue requirement are needed to implement PGE's new Strategic Asset Management (SAM) plan (developed between 2013 and 2016), and PGE testifies that some of the other incremental T&D FTEs are needed to support new functionality in technology made possible by PGE's 2020 Vision.

[98] PGE/500, Henderson-Housseini-Anderson/18-21.
[99] PGE/500, Henderson-Housseini-Anderson/8-11.

Q. What amount of expense does Staff recommend eliminating from PGE's test year expense for this issue?

A. The total FTE adjustment is ($22.412) million, which is equivalent to fully-loaded costs of 124.86 FTEs, I discuss adjustments based on incremental FTEs for corporate support (A&G). Mitch Moore discusses adjustments related to incremental FTEs in PGE's information technology (IT) and transmission and distribution departments. Lance Kaufman discusses adjustments based on costs of incremental FTEs in PGE's generation departments, Max St. Brown discusses an FTE adjustment related to distribution O&M, and Rose Anderson discusses an adjustment related to FTEs in PGE's outdoor lighting department.

Q. What is your adjustment related to incremental FTEs in corporate support (A&G)?

A. I recommend that costs of 12.5 incremental FTEs should be removed from test year expense.

- **Human Resources – Safety (2 FTEs).** PGE proposes adding one FTE in 2017 and one FTE in 2018 to analyze PGE's safety reporting system to harness system benefits of improved safety metrics and to support increased training for multiple workplace injury prevention programs. PGE notes it has already had some success in reducing workplace injuries, reducing injuries by 23 percent since 2014.[100]

Ratepayers should not have to pay for additional FTEs to *analyze* PGE's safety reporting system and perform training to harness future benefits. PGE

[100] PGE/600, Lobdell-Tooman/9.

asserts they have already captured benefits from previously implemented programs and reduced injuries.[101] Previously gained efficiencies and cost decreases associated with injury reduction could pay for these FTEs.

- **Human Resources – Support Services (3.5 FTEs).** PGE plans to add 3.5 FTEs and increase outside services to assist with increases in hiring. As of, PGE had not yet hired these new FTEs, but is using temps and contract services for hiring support.[102]

Of the incremental FTEs included in PGE's proposed revenue requirement, 165 are intended are for distribution and many have already been hired and even more will be hired by the end of 2017. Staff does not believe it is reasonable to have ratepayers pay for an additional 3.5 FTEs in PGE's human resource department starting in 2018.

- **Human Resources—Training (3 FTEs)**. PGE plans to add three FTEs in 2018 and increase contract labor budget for training services. PGE is centralizing training to allow subject-matter experts in departments to spend more time on duties.[103]

PGE's request for three incremental employees and an increase to budget for outside services to expand its training department for does not take into account the resources that are freed-up in various departments when training is centralized. PGE notes that its current training model takes up time of individuals in departments and asserts centralizing its training department will create efficiencies. It is reasonable to expect that the new FTEs and the outside services should be paid for through efficiencies and cost savings rather than a rate increase.

[101] PGE/600, Lobdell-Tooman/9.
[102] PGE/600, Lobell-Tooman/12.
[103] PGE/600, Lobdell-Tooman/12.

- **Accounting and Finance – Supply Chain (2 FTEs)**. PGE plans to add two FTEs for supply chain due to centralization and streamlining of all supply chain functions. PGE states that it is centralizing procurement to improve procurement process and quality control and to free up department subject matter experts' time.

The Finance and Supply Chain Replacement Project (FSRP) was part of 2020 Vision and closed prior to 2012.[104] It is reasonable to assume that this 26.5 million investment[105] has created efficiencies in PGE's procurement process. Further, centralizing the procurement process will decrease the amount of procurement work done in various departments. It is reasonable to expect that process improvement cost savings and efficiencies should fund the new FTEs as opposed to ratepayers.

- **Accounting and Finance – Accounts Payable/Accounts Receivable (1 FTE)**. PGE hiring because needs additional compliance support for credit cards issued to employees.[106]

PGE testifies that it needs additional oversight of its auditing program to improve compliance management and provide timely review of expenditures. PGE has a five-year contract for corporation purchasing cards (P-Cards) under which PGE receives a rebate based on number of users. In other words, the rebate increases as the number of employees to whom PGE issues P-Cards increases.[107] **[BEGIN CONFIDENTIAL]** [redacted]

[104] UE 262 PGE/600, Henderson-Hosseini/4.
[105] See UE 262 PGE/600, Henderson-Hosseini/4 (stating capital costs of FSRP were $26.5 million).
[106] PGE/600, Lobdell-Tooman/21.
[107] Staff/405, Gardner, PGE Response to ICNU DR. No. 48.

[redacted] **[END CONFIDENTIAL]**[108] It appears need for additional FTE for compliance of credit card use is correlated to PGE's credit card policy. It is reasonable that PGE should manage cost of increased need for employee credit card activity compliance with cost savings associated with PGE credit card policy.

- **Accounting and Finance – Corporate Finance (1 FTE).** PGE adding one FTE to provide company-wide Enterprise Risk Management (ERM) support. PGE does not currently have full-time FTE for this. New FTE will work with organization to identify and assess particular events or circumstances in terms of likelihood and magnitude of detrimental impact and prepare response strategy.[109]

PGE's goal is laudable. However, Staff believes this additional FTE is discretionary and should not be part of rates when so many other FTEs are being added to Company for more critical projects.

Q. Do you have other adjustments to A&G expense related to the FTE adjustment?

A. In addition to the adjustments related to FTEs, Staff recommends disallowance of costs of the outside services described below.

- **Accounting and Finance – Auditing (increase contractor costs by $0.3 million).** PGE says audit services have increased their fees in 2017 by $100,000 and that it anticipates an additional $200,000 in costs because auditors will have a lot to do in 2017.[110]

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[108] Staff/406, Gardner, PGE Response to ICNDU DR No. 48. Conf. Att. A.
[109] PGE/600, Lobdell-Tooman/21.
[110] PGE/600, Lobdell-Tooman/5 and 22.

PGE's forecast of an additional $200,000 for additional auditing services is speculative and should be removed.

- **Business Continuity and Emergency Management (BECM) – $0.4 million increase in outside services).** PGE started the program in 2007 with four FTEs and added three FTEs for BECM between 2015 and 2016 and now has 7 FTEs for BECM. PGE proposes to increase budget for BCEM from $0 .8 million to 1.2 million. The projected increase to BECM costs is for the continued development and completion of the "BECM roadmap, which establishes the activities PGE needs to perform to achieve a target level of regional preparedness and resilience among PGE's primary department/systems.[111]

Staff believes a 50 percent increase in the budget for BECM is discretionary, like the costs of the FTEs identified above, and not warranted at this time.

Q. What do you mean by discretionary?

A. In its 1995 order in Docket No. UE 88, the Commission observed that some of PGE's costs in its proposed revenue requirement were "discretionary" noting that "discretionary costs can include operating and maintenance expense accounts (company labor and benefits, contract labor, office supplies and expenses, insurances, transportation, and outside services)."[112] In response to a testimony by Staff that PGE had not been sufficiently aggressive in reducing its discretionary costs to offset the impact of the closure of the Trojan Nuclear Plan, the Commission imposed a one percent disallowance on discretionary A&G costs.[113] The Commission emphasized that it did not disallow costs of specific programs, but left it to PGE to manage its discretionary costs.[114]

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[111] Order No. 95-32, p. 30. (Docket No. UE 88).
[112] Order No. 95-322, p. 30, n. 15 (Docket No. UE 88).
[113] *Id.*
[114] *Id.*, p. 30.

Similarly in this case, the costs described above for FTEs for new initiatives and programs are discretionary. Because PGE has not applied sufficient downward pressure on its proposed revenue requirement, Staff recommends a disallowance to some of PGE's discretionary costs.

Q. Is Docket No. UE 88 the only case in which the Commission has applied a general disallowance to reduce discretionary costs?

A. No. In PGE's 2001 General Rate Case (Docket No. UE 115), the Citizens' Utility Board of Oregon (CUB) and the Industrial Customers of Northwest Utilities (ICNU) recommended a downward adjustment to PGE's proposed revenue requirement for customer service costs on the basis the increase was too great for customers to absorb in light of other increasing costs in PGE's revenue requirement. The Commission shared CUB's concerns:

> After our review, we share CUB's concerns about the significant increases to PGE's Customer Service costs. While some are related to PGE's efforts to meet the requirements of SB 1149, others are in response to PGE's belief that its customers want new services, more options, and better communication channels. To address these perceived needs, PGE is adding payment options, expanding communication choices, adding new customer services, and increasing the frequency of customer surveys. PGE admits that these changes cost more, but explains that they provide more value to PGE's customers.
>
> PGE is correct that we should judge these services and the costs associated with them on the basis of the value they provide and the demand they meet. We must do so, however, in the context of PGE's overall request, which includes significant increases to its power costs. While we commend PGE for it efforts to enhance its services based on customer requests, we question whether its customers would enthusiastically support the addition of costly new programs when also faced with unprecedented power cost increases.[115]

[115] Order No. 01-0777, p. 31.

Q. Are the circumstances presented in Docket Nos. UE 88 and UE 215 analogous to those presented in this case?

A. The rate increase sought by PGE in of PGE (Trojan-related issues (UE 88) and steep increase in power costs (UE 215). However, this is the fourth in a series of PGE general rate cases in a relatively short time span: Docket No. UE 162 (2012-2013), Docket No. UE 283 (2014), and Docket No. UE 294 (2015). And, as already discussed, this case is notable for the significant amount of new initiatives and program expansions.

Q. What is Staff's recommendation regarding the incremental increase in FTEs included in the 2018 test year?

A. Staff recommends decreasing the number of incremental FTEs for purposes of determining PGE's 2018 test year expense. Including benefit loadings, this reduces the 2018 test year costs in total by ($22.412) million allocated as ($15.621) million O&M expense and as ($7.596) million capital cost.

Incentives

As explained in its testimony, PGE did make adjustments to its forecasted 2018 incentives for the 2018 test year. PGE's "pre-filing adjustment removes 100% of the Officer Long-term Incentive Program costs and 50% of the cost of all other incentives plans."[116] According to its testimony, PGE rationale for reducing incentives was "to help mitigate the overall size of the rate increase."[117]

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[116] PGE/400, Mersereau-Jaramillo/18 at 7-8.
[117] PGE/400, Mersereau-Jaramillo/18 at 12.

Based on Staff's W&S model, Staff calculated a reduction to PGE's filed incentives. In calculating the adjustment, Staff started with 2015 actual incentives and 2015 actual FTEs, and calculated an incentive amount per FTE. This amount was escalated by the CPI, and multiplied by Staff's proposed 2018 FTEs of 2,661 to arrive at a projected 2018 incentive cost. Staff removed 100 percent of the officers' incentives and allowed 50 percent of the employee incentives. The elimination of 100 percent of officers' incentive reflects Commission policy stated above. Based on PGE's testimony and responses to Staff data requests, Staff believes that the employees' incentives should be shared between customers and shareholder at 50 percent. Therefore, Staff's adjustment for exempt and non-exempt employees' incentives reflects the difference in the Staff's three-year escalation using the CPI and the Company's budgeted increase in incentives. Staff then applied the same sharing test as describe above.

Q. What is Staff's recommendation regarding the amount of incentives in the test year?

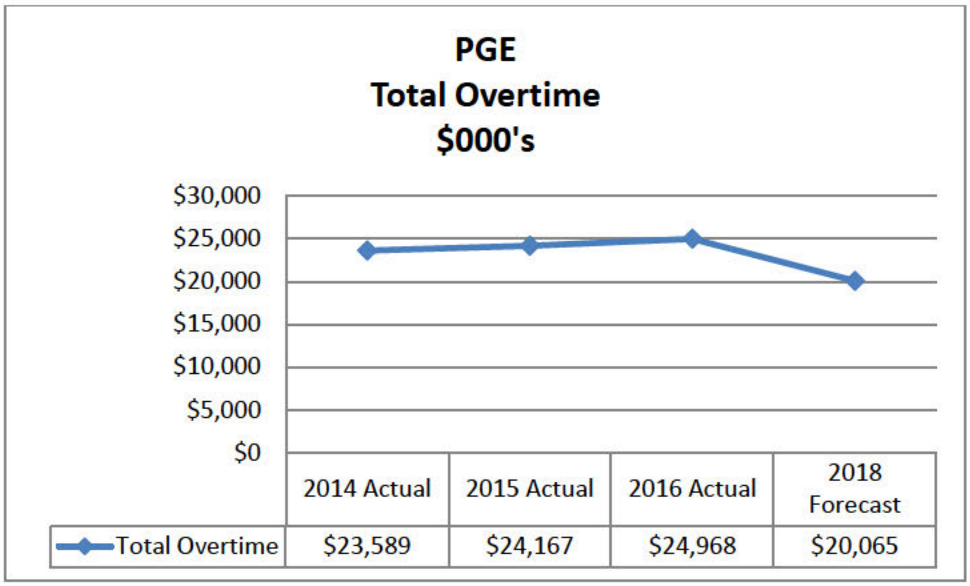
A. After application of the sharing test, Staff recommends a reduction in PGE's test year incentives of ($3.857) million, allocated respectively between O&M and capital costs as ($2.668) million, and ($1.169) million.[118]

[118] See Staff electronic workpaper, S-6 UE 319 Adj W&S Gardner, tab S-6.3 PUC 3-year Incentives.

Overtime

The Company provided overtime costs in response to Standard DR No. 92.[119] The Company's overtime costs have decreased from $24.617 million in 2015 to $20.065 million for the 2018 test year as shown the table below. Staff's projected overtime using the W&S model is $26.974 million or $6.908 million more than the Company proposed 2018 test year amount.[120]

Table 2.



	2014 Actual	2015 Actual	2016 Actual	2018 Forecast
Total Overtime	$23,589	$24,167	$24,968	$20,065

Q. What is Staff's recommendation regarding the amount of overtime cost in the test year?

A. Staff recommends no reduction in overtime costs included in PGE's 2018 test year.

[119] Exhibit/405, Gardner, PGE Response to Standard DR No. 92.
[120] See Staff electronic workpaper, S-6 UE 319 Adj W&S Gardner, tab S-9.3 PUC 3-year OT.

Other Miscellaneous Payroll

Q. Are there other adjustments that are made within the W&S model?

A. Yes. Staff also adjusts the test year payroll tax expense to reflect the decrease in taxable gross wages. Also, Staff reduces depreciation expense to reflect the reduction in capitalized compensation.

Q. What is Staff's recommendation with regard to payroll tax expense and depreciation?

A. Consistent with Staff's above recommended adjustments, Staff recommends the Commission reduce payroll taxes by ($163) thousand and depreciation expense by ($186) thousand for a total adjustment of ($349,000).

CET Cost Recovery

Q. Are there other adjustments Staff recommends related to employee compensation?

A. Yes. Staff believes that the amount of labor removed from base rates operating expenses related to the 37.91 FTE[121] included in PGE's proposed CET recovery mechanism is understated. Staff requested the total compensation for these FTE in Staff DR No. 425.[122] The Company responded that the only compensation costs included in the regulatory asset for these FTE was for wages and salaries. Staff believes all of the compensation, e.g. labor loadings such as medical benefits etc., related to these FTEs should be removed from base rates and included in the CET regulatory asset. Staff

[121] PGE/401, Mersereau-Jaramilo/1.
[122] Staff/405, Gardner, PGE Response to Staff DR No. 425.

recommends this treatment because, as PGE has expressed in testimony, this long on-going project has been pushed out and is expected to be completed in second quarter 2018.[123] Therefore, it is appropriate that the total compensation related to the 37.91 FTE be amortized with the other CET O&M costs.

Q. What is the additional amount of compensation associated with the CET FTEs that Staff recommends be removed from base rates and included in the CET regulatory asset?

A. Staff recommends $1.271 million[124] in labor loadings be removed from the 2018 test year expenses and be included in the CET regulatory asset. Staff witness Mitch Moore in Exhibit 1100 discusses Staff's proposed accounting method for the CET O&M costs in aggregate.

[123] PGE / 900 Stathis – Dillin / 7 at 22, 8 at 1-13.
[124] See Staff electronic workpaper,Total Compensation S-9.xlsx.

ISSUE 10: Non-medical Insurance

Q. What non-medical insurance costs are included in PGE's 2018 test year?

A. PGE explains that in general, its insurance coverage falls into two broad categories: Property and Casualty. PGE forecasts its Property and Casualty premiums to be approximately $11.4 million, after 50 percent of non-primary layers of Directors and Officers (D&O) insurance are excluded.[125] PGE's Test Year forecast for Property program premiums increases from its 2016 actual expense to account for an increase in total value insured and a forecasted two percent annual increase in rates.[126] Within its Casualty program, PGE expects increases in premiums in its General Liability, Workers' Compensation and Cyber Liability coverage and its Test Year forecast includes a one percent overall rate increase for Casualty program premiums. PGE forecasts that its expenditures for retained losses for its Casualty programs will increase approximately 14.1 percent annually from 2016 to 2018, resulting in a total increase in spending for retained losses of about 35 percent between 2016 and 2018.[127]

Q. What are retained losses?

A. PGE explains that retained losses are the portion PGE must absorb before insurance coverage begins for auto liability, general liability, and workers'

[125] PGE/600, Lobdell-Tooman/22-23.
[126] PGE/600, Lobdell-Tooman/23.
[127] PGE/600, Lobdell-Tooman/23.

compensation claims.[128] PGE says that its expense for retained losses is based on an actuarial project of annual expenditures that is correlated to PGE's actual loss experience over time.[129]

Q. What are Staff's conclusions regarding Property and Casualty insurance?

A. Staff concludes PGE's forecasted expense for Property and Casualty premiums is reasonable. However, Staff believes PGE's test year expense for retained losses for auto and general liability is not supported. PGE expects its retained losses for auto and general liability to increase from its actual cost of approximately **[BEGIN CONFIDENTIAL]** [redacted], **[END CONFIDENTIAL]** which is approximately a **[BEGIN CONFIDENTIAL]** [redacted].**[END CONFIDENTIAL]**[130] PGE asserts that its 2018 Test Year forecast is based on actuarial projections that are directly correlated to PGE's actual loss experience over time.[131]

PGE's loss experience in 2014, 2015, and 2016 does not support a 35 percent increase.

2014: **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

2015: **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

2016: **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[132]

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[128] PGE/600, Lobdell-Tooman/23.
[129] PGE/600, Lobdell-Tooman/23.
[130] Staff/406, PGE Confidential Response to Standard DR No. 68, Att. B.
[131] PGE/600, Lobdell-Tooman/26, lines 1-4.
[132] Staff/406, PGE Confidential Response to Standard DR No. 68, Att. B.

Staff recommends adjusting PGE's 2018 test year retained losses to be more consistent with its actual losses 2014-2016. The percentage increase between 2014 and 2016 is approximately 0.05 percent. The percentage decrease between 2014 and 2015 is approximately 24 percent and the increase between 2015 and 2016 is approximately 39 percent. Based on a linear trend of the four year's data points, Staff recommends an adjustment of ($502,476).

Q. Does PGE have other non-medical insurance?

A. Yes, PGE has insurance for directors and officers (D&O insurance).

Q. What is the Commission's treatment of D&O insurance?

A. In its 2008 order in Docket No. UE 197, the Commission agreed with Staff that cost of D&O liability insurance should be split between ratepayers and shareholders and ordered that the cost of D&O insurance be split 50/50 between the Company and ratepayers.

Q. What does PGE include in its revenue requirement for D&O insurance expense?

A. PGE includes the cost of the primary layer of D&O insurance and 50 percent of the excess layers.

Q. Does Staff propose an adjustment to PGE's Test Year expense for D&O insurance?

A. Yes. Consistent with the Commission's ruling in 2008, Staff recommends adjusting the Company's Test Year expense for D&O insurance so that the amount included is half of the Company's forecasted expense for the 2018

Test Year. To accomplish this, Staff recommends removing half of the cost of the primary layer of D&O insurance, which equals an adjustment of ($272,476).

ISSUE 11: Employee Medical Benefits

Q. What costs for employee benefits are included in PGE's Test Year Forecast?

A. PGE explains that there are four components of employee benefits: (1) health and wellness, (2) disability and life insurance, (3) post-retirement, and (4) miscellaneous benefits.[133] For the 2018 Test Year, PGE forecasts total expense of $97,832,000, which is a $14,622,000 (8.4 percent) increase on an average annual basis over its actual expense in 2016 of $83,210,000.[134] PGE states that the primary drivers of the forecasted increase are anticipated increases in medical and dental rates from benefit providers and PGE's forecasted increase to FTEs.[135] The forecasted increase in FTEs accounts for $2.6 million of the increase of forecasted benefits.[136]

Q. Does Staff recommend an adjustment to PGE's Test Year expense for benefits?

A. Yes. As discussed in more detail below, Staff is recommending that the Commission disallow 2018 Test Year costs for 124.86 of the incremental FTEs that are included in PGE's Test Year forecast. Eliminating benefits costs for 124.86 FTEs reduces the 2018 Test Year expense by ($4.182) million.

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[133] PGE/400, Mersereau-Jaramillo/23, lines 11-12.
[134] PGE/400, Mersereau-Jaramillo/23, lines 14-16.
[135] PGE/400, Mersereau-Jaramillo/25, lines 1-5.
[136] PGE/400, Mersereau-Jaramillo/25, lines 4-5.

Q. Does this conclude your opening testimony?

A. Yes.

CASE: UE 319
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualifications Statement

June 16, 2017

ITNESS QUALIFICATION STATEMENT

NAME: Marianne Gardner

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Revenue Requirement Analyst
Energy Rates, Finance and Audit Division

ADDRESS: 201 High Street SE., Suite 100
Salem, OR. 97301

EDUCATION: Master of Business Administration
Oregon State University, Corvallis, Oregon

Bachelor of Science in Accounting
Montana State University, Bozeman, Montana

CPA, Oregon

EXPERIENCE: I have been employed by the Public Utility Commission of Oregon since March 2013, with my current position being a Senior Revenue Requirement Analyst, in the Energy - Rates, Finance and Audit Division. My responsibilities include research, analysis, and recommendations on a range of cost, revenue and policy issues for electric and natural gas utilities. As the revenue requirement summary witness, I have provided testimony in dockets UE 263, UG 246, UE 283, UE 294, UG 284, UG 287, UG 288, and UG 305.

I have approximately 20 years of professional accounting experience, including:

- Thirteen years as a cost accountant with responsibilities including cost accounting, budgeting, product costing, and the preparation of management reports;

- Four years experience in public accounting working in the areas of audit, tax and financial accounting for individual and small business clientele; and,

- Three years experience in non-profit accounting for an agency administrating funds under the Federal Job Training Partnership Act.

CASE: UE 319
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 402

Exhibits in Support
Of Opening Testimony

June 16, 2017

PGE UE 319
Test Year Ending December 31, 2018
000's of Dollars

Uncollectible Adjustment

See Staff Opening Testimony. Staff/400, Gardner.

	Company Filing		Staff		Adjustment	
Description/ Account No.	Total Company	OR-Allocated	Total Company	OR-Allocated	Total Company	OR-Allocated
Uncollectible Expense		$ 6,599		$ 6,118	$ -	$ (480)
2018 Test Period General Revenues				$1,783,435		
Uncollectible Rate				0.3431%		
Bad debt expense		$ 6,599		$ 6,118		
Uncollectible rate for revenue sensitive		0.37000%		0.3431%		-0.0269%
Proof for Uncollectible rate adjustment NTG		1.7213		1.72084		(0.000479)
2018 Test Period Net Revenue				284,665		
Change in NTG factor				(0.0005)		
Uncollectible rate rev. requirement				(136)		

Staff Initiator:
Marianne Gardner

CASE: UE 319
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 403

Exhibits in Support
Of Opening Testimony

June 16, 2017

PGE UE 319
Test Year Ending 12/31/2018
000's

Wages,Salaries,FTE,Incentives,OT, CET benefit loading, & Benefit loadings - adjusted FTE

See Opening Testimony Staff/400, Gardner.

Preliminary Adjustment

Description/ Account No.	Company-Wide: Company Filing	Company-Wide: Staff	Company-Wide: O&M Adjustment	Company-Wide: Capital Adjustment	OR- Allocated: O&M Adjustment	OR- Allocated: Capital Adjustment
Wages & Salaries	$ 272,827	$ 269,865	$ (2,064)	$ (897)	$ (2,064)	$ (897)
FTE Adjustment	$ 269,865	$ 251,635	$ (12,706)	$ (5,524)	$ (12,706)	$ (5,524)
Incentives	$ 12,914	$ 9,057	$ (2,688)	$ (1,169)	$ (2,688)	$ (1,169)
Overtime	$ 20,065	$ 20,065	$ -	$ -	$ -	$ -
CET Benefits loadings					(1,271)	
Benefit loadings - adjusted FTE					$ (2,915)	$ (1,267)
Total OR - Allocated Adjustments					**$ (21,645)**	**$ (8,857)**
Payroll Taxes	$ 16,109	$15,946	$ (163)		**$ (163)**	
Depreciation O&M Adjustment Associated with Capital Adjustment					**$ (244)**	

Staff Initiator:
Marianne Gardner

CASE: UE 319
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 404

Exhibits in Support
Of Opening Testimony

June 16, 2017

APPENDIX A: ECONOMIC FORECAST DETAIL

Table A.1 – Employment Forecast Tracking

Total Nonfarm Employment, 1st quarter 2017

(Employment in thousands, Annualized Percent Change)

	Preliminary Estimate		Forecast		Forecast Error		Y/Y Change
	level	% ch	level	% ch	level	%	% ch
Total Nonfarm	1,850.4	2.1	1,859.7	3.0	(9.3)	(0.5)	1.7
Total Private	1,542.2	2.4	1,546.3	2.6	(4.0)	(0.3)	1.8
Mining and Logging	7.5	(0.3)	7.6	0.8	(0.1)	(0.9)	(4.3)
Construction	94.4	9.0	93.3	1.0	1.1	1.2	6.9
Manufacturing	189.4	2.3	186.7	(0.6)	2.7	1.4	0.2
Durable Goods	131.3	0.8	129.7	(1.4)	1.6	1.2	(0.6)
Wood Product	23.0	2.0	22.7	0.1	0.3	1.3	0.9
Metals and Machinery	36.8	0.5	36.8	0.8	0.0	0.1	0.0
Computer and Electronic Product	37.8	(1.6)	37.5	(0.9)	0.3	0.9	(1.7)
Transportation Equipment	12.0	1.3	11.8	(5.6)	0.2	2.0	(4.4)
Other Durable Goods	21.8	4.1	21.1	(5.1)	0.7	3.2	1.1
Nondurable Goods	58.1	5.7	57.0	1.3	1.1	2.0	2.1
Food	29.8	5.0	28.9	1.0	0.8	2.9	1.8
Other Nondurable Goods	28.3	6.4	28.0	1.6	0.3	1.0	2.4
Trade, Transportation & Utilities	343.7	0.4	345.1	2.3	(1.4)	(0.4)	1.1
Retail Trade	205.6	0.2	207.1	1.7	(1.5)	(0.7)	0.2
Wholesale Trade	75.8	0.5	76.8	5.8	(0.9)	(1.2)	1.0
Transportation, Warehousing & Utilities	62.2	1.2	61.3	0.5	0.9	1.5	4.5
Information	33.2	2.3	34.0	2.9	(0.8)	(2.4)	(0.3)
Financial Activities	97.3	3.9	96.8	0.1	0.5	0.5	1.6
Professional & Business Services	238.9	4.2	242.9	4.4	(4.0)	(1.6)	0.8
Educational & Health Services	271.2	2.1	272.9	3.3	(1.6)	(0.6)	2.9
Educational Services	35.5	(0.1)	36.1	1.2	(0.6)	(1.7)	(0.9)
Health Services	235.8	2.5	236.8	3.7	(1.0)	(0.4)	3.5
Leisure and Hospitality	202.4	2.1	202.7	6.2	(0.4)	(0.2)	2.4
Other Services	64.2	(1.0)	64.3	(1.3)	(0.1)	(0.1)	2.0
Government	308.2	0.7	313.5	5.1	(5.3)	(1.7)	1.1
Federal	27.8	(5.1)	28.5	0.7	(0.7)	(2.5)	(0.7)
State	55.4	(11.3)	90.2	3.4	(34.7)	(38.5)	2.1
State Education	0.7	(71.2)	33.5	(2.4)	(32.8)	(97.8)	12.9
Local	224.9	4.7	194.8	6.5	30.1	15.5	1.0
Local Education	131.9	6.8	101.4	3.2	30.5	30.0	0.3

Table A.2 – Short-Term Oregon Economic Summary

Oregon Forecast Summary

	Quarterly					Annual					
	2017:1	2017:2	2017:3	2017:4	2018:1	2016	2017	2018	2019	2020	2021
Personal Income ($ billions)											
Nominal Personal Income	189.7	192.5	195.1	197.8	200.7	184.4	193.8	204.9	216.7	228.6	240.1
% change	5.5	6.0	5.5	5.6	6.0	4.5	5.1	5.7	5.7	5.5	5.0
Real Personal Income (base year=2005)	169.2	171.1	172.8	174.6	176.7	166.6	171.9	179.2	185.6	191.3	196.1
% change	2.9	4.7	4.1	4.2	4.9	3.4	3.2	4.2	3.6	3.0	2.5
Nominal Wages and Salaries	100.4	102.0	103.7	105.3	107.0	96.8	102.9	109.4	115.8	122.0	128.1
% change	7.4	6.9	6.7	6.5	6.6	6.2	6.3	6.4	5.8	5.4	5.0
Other Indicators											
Per Capita Income ($1,000)	46.0	46.5	47.0	47.5	48.0	45.1	46.8	48.8	50.9	53.0	55.0
% change	4.1	4.4	3.8	4.2	4.7	3.0	3.6	4.3	4.4	4.2	3.8
Average Wage rate ($1,000)	53.8	54.3	54.8	55.4	55.9	52.4	54.6	56.7	59.1	61.7	64.3
% change	5.2	4.2	4.0	3.9	4.0	3.3	4.2	4.0	4.1	4.4	4.3
Population (Millions)	4.1	4.1	4.2	4.2	4.2	4.08	4.15	4.20	4.26	4.31	4.36
% change	1.3	1.5	1.7	1.3	1.2	1.5	1.5	1.4	1.3	1.3	1.2
Housing Starts (Thousands)	18.7	21.1	21.5	22.1	22.4	19.1	20.8	22.8	23.1	24.0	24.5
% change	8.0	61.3	7.9	12.8	5.1	19.5	9.4	9.6	1.2	3.8	2.2
Unemployment Rate	4.0	3.9	4.1	4.2	4.3	4.9	4.1	4.4	4.5	4.7	4.8
Point Change	(0.6)	(0.1)	0.2	0.1	0.1	(0.7)	(0.8)	0.4	0.1	0.1	0.1
Employment (Thousands)											
Total Nonfarm	1,850.4	1,862.3	1,874.5	1,886.2	1,897.9	1,831.7	1,868.3	1,912.7	1,943.9	1,963.4	1,977.6
% change	2.1	2.6	2.6	2.5	2.5	2.8	2.0	2.4	1.6	1.0	0.7
Private Nonfarm	1,542.2	1,552.3	1,562.7	1,572.9	1,583.2	1,524.6	1,557.5	1,595.9	1,622.0	1,636.1	1,648.2
% change	2.4	2.6	2.7	2.6	2.6	3.0	2.2	2.5	1.6	0.9	0.7
Construction	94.4	95.2	95.9	96.4	96.9	90.1	95.5	97.6	98.4	98.8	99.5
% change	9.0	3.4	2.7	2.3	2.2	8.2	5.9	2.2	0.8	0.4	0.7
Manufacturing	189.4	190.0	190.5	190.9	191.5	188.2	190.2	192.1	193.3	194.2	195.2
% change	2.3	1.3	1.0	0.9	1.2	1.0	1.1	1.0	0.6	0.5	0.5
Durable Manufacturing	131.3	131.7	131.9	132.1	132.6	131.2	131.8	133.0	133.7	134.1	134.7
% change	0.8	1.1	0.7	0.7	1.3	0.6	0.4	0.9	0.5	0.3	0.4
Wood Product Manufacturing	23.0	23.0	23.1	23.1	23.2	22.7	23.1	23.2	23.3	23.3	23.5
% change	2.0	1.0	1.0	0.8	0.5	1.1	1.3	0.6	0.3	0.3	0.8
High Tech Manufacturing	37.8	37.9	38.0	38.1	38.2	38.2	37.9	38.2	38.0	37.7	37.6
% change	(1.6)	1.2	0.9	1.0	1.1	1.2	(0.6)	0.8	(0.5)	(0.8)	(0.4)
Transportation Equipment	12.0	12.0	11.9	11.8	11.9	12.1	11.9	12.1	12.3	12.4	12.5
% change	1.3	(0.8)	(3.6)	(1.8)	3.6	(2.9)	(1.8)	1.4	1.7	0.9	0.9
Nondurable Manufacturing	58.1	58.3	58.5	58.7	58.9	56.9	58.4	59.1	59.6	60.1	60.5
% change	5.7	1.8	1.5	1.3	1.1	2.1	2.6	1.1	0.9	0.9	0.7
Private nonmanufacturing	1,354.0	1,362.3	1,372.2	1,382.1	1,391.7	1,336.4	1,367.6	1,403.9	1,428.7	1,441.9	1,453.0
% change	2.8	2.5	3.0	2.9	2.8	3.3	2.3	2.7	1.8	0.9	0.8
Retail Trade	205.6	206.6	207.4	208.3	209.1	205.6	207.0	210.3	213.1	215.2	216.5
% change	0.2	1.9	1.6	1.6	1.6	1.6	0.7	1.6	1.3	1.0	0.6
Wholesale Trade	75.8	76.3	76.7	77.1	77.3	75.6	76.5	77.5	78.1	78.7	79.0
% change	0.5	2.5	2.1	1.8	1.0	2.1	1.2	1.4	0.7	0.8	0.4
Information	33.2	33.5	33.6	33.7	33.7	33.3	33.5	33.9	34.4	34.7	34.8
% change	2.3	2.9	1.9	0.5	0.8	1.1	0.6	1.4	1.4	0.8	0.3
Professional and Business Services	238.9	242.2	245.5	248.8	252.1	237.5	243.9	256.6	266.7	272.0	277.2
% change	4.2	5.7	5.6	5.4	5.4	3.6	2.7	5.2	3.9	2.0	1.9
Health Services	235.8	237.5	239.2	240.9	242.5	230.8	238.3	244.6	247.8	250.7	254.4
% change	2.5	3.0	2.8	3.0	2.6	3.7	3.2	2.6	1.3	1.2	1.5
Leisure and Hospitality	202.4	203.7	205.4	207.0	209.1	199.5	204.6	210.7	214.4	215.0	214.2
% change	2.1	2.7	3.3	3.1	4.1	4.1	2.6	3.0	1.8	0.2	(0.3)
Government	308.2	310.1	311.8	313.2	314.7	307.0	310.8	316.8	321.9	327.3	329.4
% change	0.7	2.5	2.2	1.9	1.9	2.0	1.2	1.9	1.6	1.7	0.6

Table A.3 – Oregon Economic Forecast Change

Oregon Forecast Change (Current vs. Last)

	Quarterly					Annual					
	2017:1	2017:2	2017:3	2017:4	2018:1	2016	2017	2018	2019	2020	2021
Personal Income ($ billions)											
Nominal Personal Income	189.7	192.5	195.1	197.8	200.7	184.4	193.8	204.9	216.7	228.6	240.1
% change	(0.8)	(0.6)	(0.6)	(0.7)	(0.7)	(0.5)	(0.7)	(0.8)	(0.7)	(0.6)	(0.4)
Real Personal Income (base year=2005)	169.2	171.1	172.8	174.6	176.7	166.6	171.9	179.2	185.6	191.3	196.1
% change	(0.9)	(0.7)	(0.7)	(0.7)	(0.6)	(0.5)	(0.8)	(0.7)	(0.6)	(0.6)	(0.6)
Nominal Wages and Salaries	100.4	102.0	103.7	105.3	107.0	96.8	102.9	109.4	115.8	122.0	128.1
% change	(1.2)	(1.0)	(0.9)	(0.9)	(0.9)	(0.9)	(1.0)	(1.0)	(1.0)	(0.9)	(0.8)
Other Indicators											
Per Capita Income ($1,000)	46.0	46.5	47.0	47.5	48.0	45.1	46.8	48.8	50.9	53.0	55.0
% change	(0.8)	(0.6)	(0.6)	(0.7)	(0.7)	(0.5)	(0.7)	(0.8)	(0.7)	(0.6)	(0.4)
Average Wage rate ($1,000)	53.8	54.3	54.8	55.4	55.9	52.4	54.6	56.7	59.1	61.7	64.3
% change	(0.7)	(0.6)	(0.5)	(0.6)	(0.5)	(0.8)	(0.6)	(0.6)	(0.6)	(0.6)	(0.5)
Population (Millions)	4.12	4.14	4.15	4.2	4.2	4.08	4.15	4.20	4.26	4.31	4.36
% change	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.0	0.0	0.0
Housing Starts (Thousands)	18.7	21.1	21.5	22.1	22.4	19.1	20.8	22.8	23.1	24.0	24.5
% change	(6.5)	1.2	(0.1)	0.1	(0.5)	(0.1)	(1.2)	(0.2)	(0.2)	(0.1)	(0.1)
Unemployment Rate	4.0	3.9	4.1	4.2	4.3	4.9	4.1	4.4	4.5	4.7	4.8
Point Change	(1.0)	(1.2)	(1.0)	(1.0)	(1.0)	(0.1)	(1.1)	(0.9)	(0.8)	(0.7)	(0.6)
Employment (Thousands)											
Total Nonfarm	1,850.4	1,862.3	1,874.5	1,886.2	1,897.9	1,831.7	1,868.3	1,912.7	1,943.9	1,963.4	1,977.6
% change	(0.5)	(0.5)	(0.4)	(0.4)	(0.4)	(0.0)	(0.4)	(0.4)	(0.3)	(0.3)	(0.2)
Private Nonfarm	1,542.2	1,552.3	1,562.7	1,572.9	1,583.2	1,524.6	1,557.5	1,595.9	1,622.0	1,636.1	1,648.2
% change	(0.3)	(0.2)	(0.2)	(0.2)	(0.2)	(0.0)	(0.2)	(0.3)	(0.3)	(0.3)	(0.2)
Construction	94.4	95.2	95.9	96.4	96.9	90.1	95.5	97.6	98.4	98.8	99.5
% change	1.2	2.0	2.3	2.4	2.6	(0.2)	2.0	3.0	3.7	3.8	3.8
Manufacturing	189.4	190.0	190.5	190.9	191.5	188.2	190.2	192.1	193.3	194.2	195.2
% change	1.4	1.6	1.7	1.7	1.7	0.1	1.6	1.8	1.6	1.5	1.5
Durable Manufacturing	131.3	131.7	131.9	132.1	132.6	131.2	131.8	133.0	133.7	134.1	134.7
% change	1.2	1.3	1.3	1.4	1.4	0.1	1.3	1.4	1.3	1.1	1.1
Wood Product Manufacturing	23.0	23.0	23.1	23.1	23.2	22.7	23.1	23.2	23.3	23.3	23.5
% change	1.3	1.3	1.3	1.3	1.3	0.2	1.3	1.3	1.3	1.3	1.3
High Tech Manufacturing	37.8	37.9	38.0	38.1	38.2	38.2	37.9	38.2	38.0	37.7	37.6
% change	0.9	1.3	1.4	1.8	1.6	0.0	1.3	1.6	1.0	0.4	0.5
Transportation Equipment	12.0	12.0	11.9	11.8	11.9	12.1	11.9	12.1	12.3	12.4	12.5
% change	2.0	2.0	2.0	2.0	2.0	0.1	2.0	2.0	2.0	2.0	2.0
Nondurable Manufacturing	58.1	58.3	58.5	58.7	58.9	56.9	58.4	59.1	59.6	60.1	60.5
% change	2.0	2.2	2.3	2.5	2.6	0.2	2.2	2.6	2.5	2.5	2.4
Private nonmanufacturing	1,354.0	1,362.3	1,372.2	1,382.1	1,391.7	1,336.4	1,367.6	1,403.9	1,428.7	1,441.9	1,453.0
% change	(0.4)	(0.5)	(0.5)	(0.4)	(0.5)	(0.0)	(0.4)	(0.6)	(0.5)	(0.5)	(0.4)
Retail Trade	205.6	206.6	207.4	208.3	209.1	205.6	207.0	210.3	213.1	215.2	216.5
% change	(0.7)	(0.8)	(0.8)	(0.6)	(0.7)	(0.0)	(0.7)	(0.8)	(0.9)	(0.7)	(0.7)
Wholesale Trade	75.8	76.3	76.7	77.1	77.3	75.6	76.5	77.5	78.1	78.7	79.0
% change	(1.2)	(0.8)	(0.5)	(0.3)	(0.4)	0.3	(0.7)	(0.5)	(0.7)	(0.7)	(0.8)
Information	33.2	33.5	33.6	33.7	33.7	33.3	33.5	33.9	34.4	34.7	34.8
% change	(2.4)	(2.1)	(1.8)	(1.9)	(2.0)	(0.4)	(2.0)	(2.1)	(1.9)	(1.8)	(1.7)
Professional and Business Services	238.9	242.2	245.5	248.8	252.1	237.5	243.9	256.6	266.7	272.0	277.2
% change	(1.6)	(1.6)	(1.6)	(1.8)	(2.0)	(0.6)	(1.6)	(2.1)	(1.8)	(1.4)	(0.9)
Health Services	235.8	237.5	239.2	240.9	242.5	230.8	238.3	244.6	247.8	250.7	254.4
% change	(0.4)	(0.6)	(0.7)	(0.8)	(0.9)	(0.2)	(0.6)	(0.9)	(1.1)	(1.3)	(1.2)
Leisure and Hospitality	202.4	203.7	205.4	207.0	209.1	199.5	204.6	210.7	214.4	215.0	214.2
% change	(0.2)	(0.2)	(0.3)	(0.3)	(0.2)	0.3	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Government	308.2	310.1	311.8	313.2	314.7	307.0	310.8	316.8	321.9	327.3	329.4
% change	(1.7)	(1.5)	(1.4)	(1.3)	(1.1)	(0.2)	(1.5)	(1.0)	(0.6)	(0.7)	(0.6)

Table A.4 – Annual Economic Forecast

May 2017 - Personal Income

(Billions of Current Dollars)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Personal Income*												
Oregon	165.6	176.4	184.4	193.8	204.9	216.7	228.6	240.1	252.1	264.1	277.1	290.7
% Ch	6.7	6.5	4.5	5.1	5.7	5.7	5.5	5.0	5.0	4.8	4.9	4.9
U.S.	14,809.8	15,458.5	16,011.6	16,725.7	17,581.2	18,525.7	19,475.9	20,437.6	21,442.6	22,483.9	23,563.5	24,679.0
% Ch	5.2	4.4	3.6	4.5	5.1	5.4	5.1	4.9	4.9	4.9	4.8	4.7
Wage and Salary												
Oregon	85.1	91.1	96.8	102.9	109.4	115.8	122.0	128.1	134.4	140.7	147.6	155.0
% Ch	6.1	7.1	6.2	6.3	6.4	5.8	5.4	5.0	4.9	4.7	4.9	5.0
U.S.	7,476.3	7,854.8	8,189.2	8,600.1	9,072.9	9,566.4	10,062.2	10,585.7	11,139.9	11,713.7	12,298.7	12,905.5
% Ch	5.1	5.1	4.3	5.0	5.5	5.4	5.2	5.2	5.2	5.2	5.0	4.9
Other Labor Income												
Oregon	19.7	21.1	22.2	23.1	24.1	25.1	26.4	27.6	28.8	30.0	31.3	32.6
% Ch	0.9	7.0	5.3	4.0	4.1	4.5	4.8	4.6	4.3	4.2	4.3	4.2
U.S.	1,229.8	1,270.5	1,325.4	1,367.7	1,402.2	1,452.8	1,509.3	1,561.5	1,615.1	1,671.3	1,729.5	1,789.6
% Ch	2.6	3.3	4.3	3.2	2.5	3.6	3.9	3.5	3.4	3.5	3.5	3.5
Nonfarm Proprietor's Income												
Oregon	12.2	13.3	14.1	14.9	15.7	16.4	17.1	17.8	18.6	19.4	20.2	21.1
% Ch	8.8	8.9	6.0	6.0	5.3	4.5	3.9	4.1	4.4	4.4	4.3	4.5
U.S.	1,269.2	1,336.8	1,389.7	1,473.3	1,553.3	1,617.9	1,675.7	1,741.6	1,813.1	1,886.1	1,962.5	2,044.2
% Ch	6.0	5.3	4.0	6.0	5.4	4.2	3.6	3.9	4.1	4.0	4.0	4.2
Dividend, Interest and Rent												
Oregon	32.9	34.1	34.7	36.4	38.6	41.3	43.9	46.1	48.1	50.1	51.9	53.7
% Ch	8.0	3.4	2.0	4.8	5.9	7.0	6.4	5.0	4.3	4.1	3.7	3.5
U.S.	2,833.1	2,913.5	2,967.6	3,089.9	3,251.3	3,465.4	3,666.4	3,831.7	3,983.9	4,136.4	4,291.7	4,441.0
% Ch	8.0	2.8	1.9	4.1	5.2	6.6	5.8	4.5	4.0	3.8	3.8	3.5
Transfer Payments												
Oregon	33.5	35.7	36.7	37.9	39.8	42.1	44.5	47.1	50.0	53.2	56.7	60.4
% Ch	8.9	6.4	2.7	3.3	5.2	5.5	5.8	5.8	6.3	6.3	6.6	6.5
U.S.	2,494.9	2,627.2	2,722.1	2,819.5	2,961.1	3,121.3	3,301.1	3,497.4	3,714.1	3,946.3	4,197.8	4,464.3
% Ch	4.5	5.3	3.6	3.6	5.0	5.4	5.8	5.9	6.2	6.3	6.4	6.3
Contributions for Social Security												
Oregon	15.0	15.9	16.8	17.7	18.8	20.0	21.1	22.3	23.4	24.7	26.0	27.4
% Ch	5.9	5.6	5.5	5.8	6.3	6.0	5.6	5.6	5.1	5.5	5.4	5.3
U.S.	607.6	635.7	663.6	698.9	738.1	777.6	818.0	861.4	905.6	952.9	1,000.5	1,050.2
% Ch	5.1	4.6	4.4	5.3	5.6	5.3	5.2	5.3	5.1	5.2	5.0	5.0
Residence Adjustment												
Oregon	(3.5)	(3.9)	(4.1)	(4.2)	(4.3)	(4.4)	(4.5)	(4.5)	(4.6)	(4.7)	(4.8)	(5.0)
% Ch	(1.1)	11.5	5.8	2.4	2.2	2.1	2.0	2.1	1.8	2.0	2.8	3.0
Farm Proprietor's Income												
Oregon	0.6	0.9	0.7	0.5	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3
% Ch	1.7	46.6	(15.2)	(31.5)	(19.0)	(13.5)	(9.3)	(3.9)	(12.4)	(2.5)	1.3	1.5
Per Capita Income (Thousands of $)												
Oregon	41.7	43.8	45.1	46.8	48.8	50.9	53.0	55.0	57.1	59.2	61.5	63.8
% Ch	5.5	5.1	3.0	3.6	4.3	4.3	4.2	3.8	3.8	3.7	3.8	3.8
U.S.	46.4	48.0	49.3	51.1	53.3	55.7	58.1	60.5	63.0	65.6	68.2	70.9
% Ch	4.4	3.6	2.8	3.6	4.3	4.5	4.3	4.1	4.1	4.1	4.0	4.0

* Personal Income includes all classes of income minus Contributions for Social Security

May 2017 - Employment By Industry
(Oregon - Thousands, U.S. - Millions)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Nonfarm												
Oregon	1,722.0	1,781.1	1,831.7	1,868.3	1,912.7	1,943.9	1,963.4	1,977.6	1,990.9	2,002.9	2,017.9	2,035.8
% Ch	2.9	3.4	2.8	2.0	2.4	1.6	1.0	0.7	0.7	0.6	0.7	0.9
U.S.	138.9	141.8	144.3	146.6	148.6	150.3	151.7	152.8	154.0	155.2	156.3	157.3
% Ch	1.9	2.1	1.8	1.6	1.4	1.1	0.9	0.7	0.8	0.8	0.7	0.7
Private Nonfarm												
Oregon	1,428.1	1,479.9	1,524.6	1,557.5	1,595.9	1,622.0	1,636.1	1,648.2	1,658.0	1,666.8	1,678.6	1,692.8
% Ch	3.1	3.6	3.0	2.2	2.5	1.6	0.9	0.7	0.6	0.5	0.7	0.8
U.S.	117.1	119.8	122.1	124.3	126.3	127.8	128.9	130.1	131.3	132.4	133.5	134.4
% Ch	2.2	2.3	1.9	1.8	1.6	1.2	0.9	0.9	0.9	0.9	0.8	0.7
Mining and Logging												
Oregon	7.7	7.8	7.7	7.7	7.8	7.8	7.8	7.9	7.9	7.9	7.9	7.9
% Ch	1.8	0.5	(0.9)	(0.1)	1.0	0.4	0.4	0.4	0.3	0.1	0.2	0.4
U.S.	0.9	0.8	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8
% Ch	3.2	(8.7)	(16.6)	5.0	3.6	1.5	2.6	2.9	2.0	1.4	1.4	0.4
Construction												
Oregon	80.1	83.3	90.1	95.5	97.6	98.4	98.8	99.5	100.0	100.6	100.9	101.5
% Ch	8.0	4.0	8.2	5.9	2.2	0.8	0.4	0.7	0.5	0.6	0.3	0.6
U.S.	6.1	6.5	6.7	7.0	7.2	7.5	7.6	7.8	8.0	8.2	8.3	8.4
% Ch	5.0	5.0	3.9	3.8	3.9	3.4	2.3	2.4	2.4	2.0	1.7	1.3
Manufacturing												
Oregon	179.6	186.2	188.2	190.2	192.1	193.3	194.2	195.2	196.1	196.7	197.5	198.5
% Ch	2.6	3.7	1.0	1.1	1.0	0.6	0.5	0.5	0.5	0.3	0.4	0.5
U.S.	12.2	12.3	12.3	12.5	12.7	12.9	13.0	13.0	13.1	13.1	13.1	13.1
% Ch	1.4	1.2	0.1	0.9	1.9	1.6	0.8	0.2	0.2	0.2	0.2	0.2
Durable Manufacturing												
Oregon	126.3	130.5	131.2	131.8	133.0	133.7	134.1	134.7	135.1	135.2	135.4	135.8
% Ch	2.4	3.3	0.6	0.4	0.9	0.5	0.3	0.4	0.3	0.0	0.1	0.3
U.S.	7.7	7.8	7.7	7.8	8.0	8.2	8.3	8.3	8.3	8.4	8.4	8.4
% Ch	1.7	1.2	(0.6)	0.8	2.7	2.2	1.1	0.4	0.5	0.4	0.4	0.5
Wood Products												
Oregon	22.0	22.5	22.7	23.1	23.2	23.3	23.3	23.5	23.7	23.7	23.7	23.9
% Ch	4.0	2.3	1.1	1.3	0.6	0.3	0.3	0.8	0.6	0.1	0.2	0.5
U.S.	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5
% Ch	5.2	2.9	2.5	2.7	5.3	5.7	4.1	3.6	3.7	3.6	2.9	2.0
Metal and Machinery												
Oregon	35.9	36.9	36.7	36.9	37.2	37.5	37.9	38.3	38.5	38.6	39.0	39.4
% Ch	1.5	2.5	(0.4)	0.6	0.8	0.8	1.1	0.9	0.5	0.5	0.8	1.1
U.S.	3.0	3.0	2.9	2.9	3.0	3.1	3.1	3.2	3.2	3.3	3.3	3.3
% Ch	1.7	(0.2)	(3.0)	0.5	3.4	3.4	1.5	0.5	1.4	1.5	1.5	1.0
Computer and Electronic Products												
Oregon	36.6	37.7	38.2	37.9	38.2	38.0	37.7	37.6	37.5	37.3	37.0	36.8
% Ch	(0.1)	3.1	1.2	(0.6)	0.8	(0.5)	(0.8)	(0.4)	(0.1)	(0.7)	(0.7)	(0.5)
U.S.	1.0	1.1	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
% Ch	(1.5)	0.4	(0.5)	0.4	3.7	0.8	(0.3)	0.5	0.7	0.3	0.3	0.2
Transportation Equipment												
Oregon	11.5	12.5	12.1	11.9	12.1	12.3	12.4	12.5	12.5	12.4	12.3	12.3
% Ch	6.0	8.5	(2.9)	(1.8)	1.4	1.7	0.9	0.9	(0.1)	(0.6)	(0.6)	(0.4)
U.S.	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.5	1.5	1.5
% Ch	3.3	2.9	1.3	(1.2)	0.1	0.3	1.3	(0.5)	(2.9)	(3.2)	(2.7)	(0.6)
Other Durables												
Oregon	20.3	20.9	21.5	21.9	22.3	22.6	22.7	22.8	23.0	23.2	23.4	23.5
% Ch	5.4	3.3	2.8	2.0	1.6	1.5	0.5	0.4	0.8	0.8	0.7	0.6
U.S.	2.1	2.1	2.2	2.2	2.3	2.4	2.4	2.4	2.4	2.5	2.5	2.5
% Ch	2.2	2.3	1.3	2.7	3.3	2.4	1.0	0.7	1.4	1.2	1.0	0.7
Nondurable Manufacturing												
Oregon	53.4	55.8	56.9	58.4	59.1	59.6	60.1	60.5	61.0	61.5	62.1	62.7
% Ch	3.1	4.5	2.1	2.6	1.1	0.9	0.9	0.7	0.8	0.8	0.9	1.0
U.S.	4.5	4.6	4.6	4.7	4.7	4.7	4.8	4.7	4.7	4.7	4.7	4.7
% Ch	0.9	1.3	1.3	1.2	0.5	0.6	0.3	(0.2)	(0.2)	(0.1)	(0.2)	(0.3)
Food Manufacturing												
Oregon	27.0	28.2	29.2	29.9	30.1	30.4	30.5	30.7	30.9	31.1	31.3	31.6
% Ch	4.2	4.7	3.3	2.5	0.8	0.7	0.6	0.6	0.6	0.6	0.8	0.9
U.S.	1.5	1.5	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.8	1.8	1.8
% Ch	0.7	1.8	2.8	3.4	2.3	1.7	1.4	1.0	1.2	1.4	1.3	1.0
Other Nondurable												
Oregon	26.4	27.5	27.8	28.5	28.9	29.2	29.6	29.8	30.1	30.4	30.7	31.1
% Ch	2.0	4.4	0.8	2.7	1.4	1.1	1.1	0.8	1.1	1.1	1.0	1.1
U.S.	3.0	3.1	3.1	3.1	3.1	3.1	3.1	3.0	3.0	3.0	2.9	2.9
% Ch	0.9	1.0	0.5	0.0	(0.4)	0.1	(0.3)	(0.9)	(1.0)	(0.9)	(1.0)	(1.1)
Trade, Transportation, and Utilities												
Oregon	325.7	335.4	341.7	345.9	351.3	355.8	358.9	360.6	361.2	361.5	361.4	361.7
% Ch	2.4	3.0	1.9	1.2	1.6	1.3	0.9	0.5	0.2	0.1	(0.0)	0.1
U.S.	26.4	26.9	27.2	27.5	27.7	27.8	27.8	27.8	27.8	27.8	27.8	27.8
% Ch	2.0	1.9	1.3	0.9	0.6	0.5	0.1	0.0	(0.0)	(0.1)	(0.1)	0.1

May 2017 - Employment By Industry
(Oregon - Thousands, U.S. - Millions)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Retail Trade												
Oregon	196.3	202.4	205.6	207.0	210.3	213.1	215.2	216.5	217.0	217.2	217.2	217.4
% Ch	2.5	3.1	1.6	0.7	1.6	1.3	1.0	0.6	0.2	0.1	(0.0)	0.1
U.S.	15.4	15.6	15.8	16.0	16.0	16.1	16.0	16.0	15.9	15.9	15.8	15.8
% Ch	1.9	1.6	1.4	0.8	0.4	0.3	(0.2)	(0.3)	(0.3)	(0.4)	(0.4)	(0.1)
Wholesale Trade												
Oregon	72.5	74.0	75.6	76.5	77.5	78.1	78.7	79.0	79.2	79.3	79.4	79.6
% Ch	1.5	2.0	2.1	1.2	1.4	0.7	0.8	0.4	0.3	0.1	0.1	0.2
U.S.	5.8	5.9	5.9	5.9	6.0	6.0	6.1	6.1	6.2	6.2	6.2	6.2
% Ch	1.4	0.7	0.2	1.1	0.8	0.8	0.8	0.7	0.6	0.6	0.5	0.3
Transportation and Warehousing, and Utilities												
Oregon	56.9	59.0	60.6	62.4	63.5	64.5	65.0	65.1	65.0	64.9	64.8	64.8
% Ch	3.6	3.8	2.7	3.0	1.7	1.7	0.7	0.2	(0.1)	(0.2)	(0.2)	(0.0)
U.S.	5.2	5.4	5.5	5.6	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
% Ch	3.2	4.1	2.2	1.2	1.1	0.5	0.2	0.1	0.0	(0.0)	(0.1)	0.4
Information												
Oregon	32.2	32.9	33.3	33.5	33.9	34.4	34.7	34.8	34.9	35.1	35.2	35.4
% Ch	(0.2)	2.3	1.1	0.6	1.4	1.4	0.8	0.3	0.3	0.4	0.4	0.6
U.S.	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.9	2.9	2.9	2.9
% Ch	0.8	0.9	0.8	0.0	1.1	(0.3)	0.8	0.7	0.9	1.2	1.0	0.5
Financial Activities												
Oregon	92.4	94.8	96.4	98.0	100.3	101.2	101.2	101.1	101.1	101.0	101.0	101.1
% Ch	0.9	2.6	1.7	1.6	2.3	0.9	(0.0)	(0.1)	(0.1)	(0.1)	(0.0)	0.1
U.S.	8.0	8.1	8.3	8.4	8.5	8.5	8.5	8.5	8.5	8.5	8.6	8.6
% Ch	1.1	1.8	2.0	1.8	0.5	(0.0)	(0.1)	0.2	0.3	0.3	0.4	0.2
Professional and Business Services												
Oregon	219.8	229.3	237.5	243.9	256.6	266.7	272.0	277.2	281.2	285.0	289.6	294.5
% Ch	4.9	4.3	3.6	2.7	5.2	3.9	2.0	1.9	1.4	1.4	1.6	1.7
U.S.	19.1	19.6	20.1	20.7	21.5	22.1	22.5	22.9	23.5	24.2	24.7	25.1
% Ch	2.9	3.0	2.6	2.9	3.9	2.6	1.7	2.0	2.7	2.7	2.0	1.9
Education and Health Services												
Oregon	248.5	257.8	266.6	274.0	280.6	284.3	287.6	291.5	295.5	299.8	304.9	310.4
% Ch	2.4	3.8	3.4	2.8	2.4	1.3	1.2	1.4	1.4	1.5	1.7	1.8
U.S.	21.4	22.0	22.6	23.1	23.3	23.5	23.7	24.0	24.2	24.5	24.9	25.2
% Ch	1.7	2.7	2.7	2.0	1.0	1.0	0.9	1.0	1.1	1.1	1.3	1.3
Educational Services												
Oregon	34.7	35.3	35.7	35.6	36.1	36.5	36.9	37.2	37.3	37.4	37.5	37.7
% Ch	1.9	1.6	1.2	(0.3)	1.2	1.3	1.2	0.6	0.5	0.2	0.3	0.3
U.S.	3.4	3.5	3.6	3.6	3.6	3.6	3.5	3.5	3.4	3.4	3.3	3.2
% Ch	1.8	1.6	2.6	2.0	(0.5)	(0.7)	(1.5)	(1.1)	(1.8)	(2.1)	(2.2)	(2.2)
Health Care and Social Assistance												
Oregon	213.7	222.5	230.8	238.3	244.6	247.8	250.7	254.4	258.2	262.4	267.4	272.8
% Ch	2.5	4.1	3.7	3.2	2.6	1.3	1.2	1.5	1.5	1.6	1.9	2.0
U.S.	18.0	18.6	19.1	19.4	19.7	19.9	20.2	20.5	20.8	21.2	21.6	22.0
% Ch	1.6	3.0	2.7	1.9	1.3	1.3	1.4	1.4	1.5	1.7	1.9	1.9
Leisure and Hospitality												
Oregon	182.9	191.5	199.5	204.6	210.7	214.4	215.0	214.2	213.4	212.4	212.9	213.8
% Ch	3.6	4.7	4.1	2.6	3.0	1.8	0.2	(0.3)	(0.4)	(0.5)	0.3	0.4
U.S.	14.7	15.2	15.6	15.9	16.1	16.3	16.5	16.7	16.8	16.8	16.8	16.8
% Ch	3.1	3.1	3.0	1.9	1.4	1.1	1.2	1.1	0.5	0.2	0.2	(0.2)
Other Services												
Oregon	59.2	60.9	63.7	64.4	65.0	65.6	65.9	66.2	66.6	66.8	67.2	67.7
% Ch	2.0	3.0	4.6	1.1	0.9	1.0	0.4	0.4	0.6	0.3	0.6	0.8
U.S.	5.6	5.6	5.7	5.7	5.7	5.7	5.7	5.7	5.6	5.6	5.6	5.6
% Ch	1.5	1.0	1.1	1.0	0.0	(0.7)	(0.6)	(0.1)	(0.4)	(0.5)	(0.6)	(0.5)
Government												
Oregon	293.9	301.1	307.0	310.8	316.8	321.9	327.3	329.4	333.0	336.1	339.3	343.0
% Ch	1.7	2.5	2.0	1.2	1.9	1.6	1.7	0.6	1.1	0.9	1.0	1.1
U.S.	21.9	22.0	22.2	22.3	22.3	22.4	22.8	22.7	22.7	22.8	22.9	22.9
% Ch	0.1	0.7	0.9	0.3	(0.2)	0.8	1.4	(0.3)	0.2	0.3	0.3	0.4
Federal Government												
Oregon	27.4	27.8	28.2	27.8	27.6	27.4	28.8	27.2	27.1	27.1	27.1	27.1
% Ch	(0.3)	1.2	1.7	(1.6)	(0.7)	(0.5)	4.8	(5.6)	(0.1)	0.0	(0.0)	(0.1)
U.S.	2.7	2.8	2.8	2.8	2.7	2.7	2.8	2.6	2.6	2.6	2.6	2.6
% Ch	(1.4)	0.8	1.5	(0.4)	(3.1)	(1.5)	3.9	(5.9)	(0.6)	(0.3)	(0.3)	(0.3)
State Government, Oregon												
State Total	70.8	58.0	55.9	56.3	57.8	59.0	59.7	60.4	61.0	61.7	62.4	63.2
% Ch	(12.7)	(18.1)	(3.6)	0.7	2.6	2.1	1.2	1.1	1.1	1.0	1.1	1.3
State Education	17.6	3.4	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
% Ch	(46.7)	(80.6)	(76.1)	(4.3)	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Local Government, Oregon												
Local Total	195.7	215.4	222.9	226.7	231.4	235.5	238.8	241.9	244.8	247.3	249.8	252.7
% Ch	8.6	10.1	3.5	1.7	2.1	1.7	1.4	1.3	1.2	1.0	1.0	1.2
Local Education	108.2	126.0	131.5	133.5	135.9	137.6	139.0	140.3	141.4	142.3	143.0	143.6
% Ch	15.7	16.5	4.3	1.6	1.8	1.2	1.0	0.9	0.8	0.6	0.5	0.4

May 2017 - Other Economic Indicators

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
GDP (Bil of 2009 $),												
Chain Weight (in billions of $)	15,982.3	16,397.2	16,662.1	17,057.9	17,507.3	17,915.3	18,310.1	18,715.1	19,114.6	19,503.5	19,879.3	20,257.4
% Ch	2.4	2.6	1.6	2.4	2.6	2.3	2.2	2.2	2.1	2.0	1.9	1.9
Price and Wage Indicators												
GDP Implicit Price Deflator,												
Chain Weight U.S., 2009=100	108.8	110.0	111.5	114.0	116.6	119.1	121.8	124.6	127.5	130.6	133.7	136.9
% Ch	1.8	1.1	1.3	2.3	2.3	2.1	2.2	2.3	2.4	2.4	2.4	2.4
Personal Consumption Deflator,												
Chain Weight U.S., 2009=100	109.2	109.5	110.7	112.7	114.3	116.7	119.5	122.4	125.4	128.4	131.4	134.4
% Ch	1.5	0.3	1.1	1.8	1.4	2.1	2.4	2.4	2.4	2.4	2.4	2.3
CPI, Urban Consumers,												
1982-84=100												
Portland-Salem, OR-WA	241.2	244.2	249.4	255.5	261.2	267.7	275.0	282.7	290.2	298.0	306.3	314.4
% Ch	2.4	1.2	2.1	2.4	2.2	2.5	2.7	2.8	2.7	2.7	2.8	2.7
U.S.	236.7	237.0	240.0	246.0	250.5	256.8	264.1	271.5	278.9	286.6	294.3	302.1
% Ch	1.6	0.1	1.3	2.5	1.9	2.5	2.8	2.8	2.7	2.8	2.7	2.6
Oregon Average Wage												
Rate (Thous $)	48.9	50.7	52.4	54.6	56.7	59.1	61.7	64.3	67.0	69.7	72.6	75.6
% Ch	3.2	3.7	3.3	4.2	4.0	4.1	4.4	4.3	4.2	4.1	4.2	4.1
U.S. Average Wage												
Wage Rate (Thous $)	53.8	55.4	56.7	58.7	61.1	63.7	66.3	69.3	72.3	75.5	78.7	82.0
% Ch	3.1	2.9	2.5	3.4	4.1	4.2	4.2	4.5	4.4	4.3	4.3	4.3
Housing Indicators												
FHFA Oregon Housing Price Index												
1991 Q1=100	304.9	332.6	369.9	402.2	433.6	456.3	478.1	497.6	517.2	537.2	554.8	569.5
% Ch	7.8	9.1	11.2	8.7	7.8	5.2	4.8	4.1	3.9	3.9	3.3	2.6
FHFA National Housing Price Index												
1991 Q1=100	208.8	220.5	234.0	244.1	251.7	258.3	265.8	273.3	281.1	290.8	301.4	312.4
% Ch	5.3	5.6	6.1	4.4	3.1	2.6	2.9	2.8	2.9	3.4	3.6	3.7
Housing Starts												
Oregon (Thous)	15.6	15.9	19.1	20.8	22.8	23.1	24.0	24.5	24.7	24.5	24.0	23.7
% Ch	9.2	2.5	19.5	9.4	9.6	1.2	3.8	2.2	0.6	(0.7)	(2.1)	(1.4)
U.S. (Millions)	1.0	1.1	1.2	1.3	1.3	1.4	1.4	1.5	1.5	1.5	1.5	1.5
% Ch	7.8	10.7	6.1	6.9	4.8	5.0	4.6	3.3	1.2	0.2	(0.6)	(0.9)
Other Indicators												
Unemployment Rate (%)												
Oregon	6.8	5.6	4.9	4.1	4.4	4.5	4.7	4.8	4.9	5.0	5.1	5.1
Point Change	(1.1)	(1.2)	(0.7)	(0.8)	0.4	0.1	0.1	0.1	0.1	0.1	0.1	0.0
U.S.	6.2	5.3	4.9	4.5	4.2	4.0	4.1	4.2	4.3	4.4	4.5	4.5
Point Change	(1.2)	(0.9)	(0.4)	(0.3)	(0.4)	(0.2)	0.1	0.1	0.1	0.1	0.1	0.0
Industrial Production Index												
U.S, 2002 = 100	105.1	104.4	103.1	105.5	108.5	111.0	113.1	115.2	117.1	118.9	120.4	121.7
% Ch	3.1	(0.7)	(1.2)	2.3	2.9	2.3	1.9	1.8	1.7	1.5	1.2	1.1
Prime Rate (Percent)	3.3	3.3	3.5	4.1	4.7	5.7	6.0	6.0	6.0	6.0	6.0	6.0
% Ch	0.0	0.3	7.7	16.7	15.2	19.8	6.2	0.0	0.0	0.0	0.0	0.0
Population (Millions)												
Oregon	3.97	4.02	4.08	4.15	4.20	4.26	4.31	4.36	4.41	4.46	4.51	4.55
% Ch	1.1	1.3	1.5	1.5	1.4	1.3	1.3	1.2	1.1	1.1	1.0	1.0
U.S.	319.5	322.0	324.5	327.1	329.8	332.4	335.0	337.6	340.2	342.8	345.3	347.8
% Ch	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.7	0.7
Timber Harvest (Mil Bd Ft)												
Oregon	4,125.6	3,788.1	3,800.0	3,900.0	3,960.0	4,020.0	4,080.0	4,140.0	4,200.0	4,151.8	4,150.0	4,198.4
% Ch	(1.8)	(8.2)	0.3	2.6	1.5	1.5	1.5	1.5	1.4	(1.1)	(0.0)	1.2

CASE: UE 319
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 405

Exhibits in Support
Of Opening Testimony

June 16, 2017

April 18, 2017

TO: Tyler Pepple
Bradley Van Cleve
Davison Van Cleve, P.C.

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to ICNU DR No. 048
Dated April 4, 2017

Request:

Reference the Company's response to OPUC Staff DR 128, Attachment A: Please provide workpapers supporting the hardcoded numbers in cells "K24:K26."

Response:

Park Revenue – Attachment 048-A shows the detail for the period 2014-2018. PGE's forecast is based on historical actuals which average approximately $600,000. However, PGE's forecast for 2017 and 2018 is $535,000, which is lower than the average due to future planned campground closures. See PGE's response to ICNU Data Request No. 049 a list of planned campground closures.

Energy Trust – There are no work papers. The revenue forecast is based on the contract between Energy Trust and PGE and is provided in PGE's response to OPUC Data Request No. 128, Attachment 128-D.

Disbursements and Receivables – The P-Card Rebate forecast was based on the 5-year contract price and assumes a gradual increase each year as the number of users increases each year. Attachment 048-B, which is protected and subject to Protective Order No. 17-057, provides further details on PGE's P-Card rebate.

UE 319

Attachment 048-A

Provided in Electronic Format only

Park Revenue
2014-2018

UE 319

Attachment 048-B

Provided in Electronic Format only

Protected and Subject to Protective Order No. 17-057

P-Card Rebate

February 28, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Standard Data Request No. 092
Dated February 28, 2017

Request:

For the Test Year and the preceding 4 calendar years, please provide (on a Total Company basis), a summary table (using the categories and format shown below) that includes the number of FTE's (exclude FTE's created by overtime hours) and the actual paid cash compensation broken down between base wages or salaries, overtime, and incentives or bonuses. For any calendar year included in this request for which actual data is not available for the entire calendar year, please create a calendar year using the available actual data combined with the forecast applicable to the rest of the year. Please note which months and figures are associated with both the actual and forecast data.

Year: 2XXX	Actual (Unadjusted) Paid Cash Compensation				
Category	Total Company FTE*	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers					
Exempt					
Nonexempt					
Union					
Total					
*Please Exclude Full-Time Equivalent Created by Overtime					

Response:

Attachment 092-A, tab one provides PGE FTEs, base wages and salaries. Actuals are provided for 2014 through 2016, while 2017 and 2018 are forecasted. For 2018, the FTE and dollar amounts associated with PGE's pre-filing adjustments have been apportioned to the appropriate employee categories based on both the specific forecasted reductions (for specific pre-filing reductions) and PGE's forecasted 2018 employee category percentages (for PGE's "unfilled position" reduction).

The two primary drivers for PGE's increase in FTEs are:

1. PGE's capital spending program, targeting the replacement of aging assets and strengthen the grid, to keep it safe and reliable; and
2. The enhancement of PGE's cyber security program based on a risk-based prioritization of enterprise-wide cyber initiatives as recommended by outside consultants.

PGE Exhibits 800 and 500 provide the details of these programs. Additionally, a secondary reason for some of the above FTE growth (partially reflected[1] by a reduction of overtime costs from 2016 to 2018), is a need to reduce employee overtime, which is placing undue strains on PGE employees.

The second tab of Attachment 092-A provides incentive costs for 2014 (actuals) through 2018 (forecast). PGE tracks paid incentive amounts by employee on a cash basis, while PGE's revenue requirement (including our incentive request) is provided on an accrual basis. In order to segregate PGE's incentive programs (in particular the Performance Incentive Compensation program) by employee category (union, exempt, non-exempt, officer), we apportioned the program cost by employee category pro rata, using the total base salaries for employees included within the respective incentive programs.

The third tab of Attachment 092-A provides overtime costs for 2014 (actuals) through 2018 (forecast).

[1] Please note PGE only incurs overtime costs for hourly and bargaining employees. While PGE's exempt employees do record overtime hours, they are paid a salaried rate, and not an hourly rate.

UE 319

Attachment 092-A

Provided in Electronic Format only

FTEs, Wages and Salaries, Incentives, and Overtime – 2014-2018

February 28, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Standard Data Request No. 094
Dated February 28, 2017

Request:

For the Test Year and preceding 4 calendar years, please provide a summary table in the format as shown on Union Salary Information (Attachment 94A) that includes:

> **a. The union name;**
> **b. All positions represented by a particular union;**
> **c. The number of FTE for each position (excluding FTE created by overtime hours.);**
> **d. The contracted hourly wage or salary for each position as of December 31 of each year; and**
> **e. The percent change from the previous year's hourly wage or salary.**

Response:

See Attachment 094-A for a listing of all Local Union No. 125 of International Brotherhood of Electrical Worker positions, rates, and number of employees for the years 2013, 2014, 2015, and 2016. Tab 1 includes positions filled by members of Bargaining Unit 1 and Tab 2 includes positions filled by members of Bargaining Unit 2.

Please note: listed are employee counts for each position, rather than full time equivalents (FTEs).

See PGE's Exhibit 400 work papers for FTEs and wages in the 2018 test year forecast.

UE 319

Attachment 094-A

Provided in Electronic Format only

Local Union No. 125 of International Brotherhood of Electrical Workers – Positions and Rates

April 3, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 288
Dated March 22, 2017

Request:

See line 16 of PGE/1300, Cody-Macfarlane/12 and PGE's workpaper file *DMC GRC 2018.xlsx*. Please describe which distribution categories allocate distribution O&M based on usage and which categories allocate distribution O&M based on per unit marginal capital cost.

Response:

Please see PGE's Response to OPUC Data Request No. 287.

April 5, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 294
Dated March 22, 2017

Request:

Referring to the Company's Exhibit 204, for each of the years 2014, 2015, 2016, 2017 and 2018, please provide a detailed amortization schedule that supports the amount recorded in each FERC account for each of the aforementioned years. For each FERC account, the schedule should reference the discrete assets/projects by name and identifying number, (e.g. work order number, project number), cost, date in service/ amortization start date, amortization period. The requested information is illustrated in the table below. The projects listed and types of costs are examples and should not be considered as all inclusive.

FERC Acct. #	FERC Acct. Description	Project name	Project #	Individual Work Orders or Components	Id. #	Cost	Date In Service mm/dd/yy	Amort Period (in years)	Amortization Amount by Calendar Year				
									2014	2015	2016	2017	2018 Test Year
404.0	Software Amortization												
		Western Eim	xxxx										
				e.g. Direct materials									
				Payroll costs									
				Software – (name)									
		Opower	xxx										
				Direct materials									
				Payroll costs									
				Software – (name)									

Clarified Request:

Per telephone conversation with OPUC Staff on April 3, 2017, PGE responds to the following restated data request:

Referring to PGE Exhibit 204, for each of the years 2014, 2015, 2016, 2017, and 2018, please provide detailed capital project information to support the amortization expenses recorded in FERC Account 404 (Amortization of Limited-Term Electric Plant).

Response:

Attachment 294-A provides the capitalized costs of Projects that are amortized through the Software Amortization category and recorded to Electric Plant in Service FERC Account 303 (Electric Plant in Service) - Miscellaneous Intangible Plant.

Attachment 294-B provides the capitalized cost of Projects that are amortized through the Other Intangible category and recorded to FERC Account 302 (Electric Plant in Service) - Franchises and consents.

Attachments 294-A and 294-B provide the capitalized costs by vintage year and by project name of those assets that were classified as used and useful.

UE 319

Attachment 294-A

Provided in Electronic Format only

Software Amortization

UE 319

Attachment 294-B

Provided in Electronic Format only

Other Intangible Amortization

April 5, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 295
Dated March 22, 2017

Request:

Please provide PGE's accounting policy that details how PGE accounts for the costs of computer software developed or obtained for internal use. If a formal written policy is unavailable, please provide a detailed narrative describing PGE's accounting treatment.

Response:

Attachments 295-A provide PGE's Accounting Practices and Procedures Document for Computer Software. Attachment 295 B provides the criteria for capitalizing software.

UE 319

Attachment 295-A

Provided in Electronic Format only

PGE's Accounting Practice and Procedures Document
for Computer Software

UE 319

Attachment 295-B

Provided in Electronic Format only

Software Capital Criteria

Portland General Electric Company

ACCOUNTING PRACTICES AND PROCEDURES DOCUMENT

COMPUTER SOFTWARE — **APPD 4-400-01**, **June 1, 2008**

APPLICABILITY

This policy applies to the purchase/development of software clearly identifiable as a separate system, and has been obtained or developed for internal use. The criterion contained in this document is to be applied to Application system software installed on the mainframe or a server. This policy is for applications other than web site software. See APPD 4-400-03 for the policy defining web site development.

Note: Software is classified as either an Operating System or an Application System. Policy for operating system software is found under APPD 4–500-02. The purchase of equipment/hardware associated with a project that involves the purchase/development of software is also covered under APPD 4-500-02. These costs are not included in determining if a project meets the dollar limit thresholds identified below.

CRITERIA FOR CAPITALIZING COMPUTER SOFTWARE

Software systems/applications meeting the following guidelines are capitalized as Intangible Assets (FERC Account 303) and amortized on a straight-line basis.

1. The application or enhancement must result in the addition of a new function or a new program.

   a. A new function is defined as modifications to existing internal use software that results in enabling the software to perform tasks that it was previously incapable of performing. Upgrades/enhancements normally require new software specifications and may also require a change to all or part of the existing software specifications.

2. The application/enhancement must have an expected life of at least five years at the time of installation.

3. TURN-KEY/CANNED SOFTWARE PURCHASES - The direct cost dollar amount must equal/exceed **$25,000**. The definition for this software is where it is purchased off the shelf with no enhancements (plug and play).

4. PURCHASE/DEVELOPMENT – The direct cost dollar amount must equal/exceed **$250,000** for systems meeting capital criteria as defined in this document. This type of software is the primary purpose of this documentation, where an application may be developed from the ground up, to where an application is purchased and costs are incurred to enhance/upgrade for company business.

ACCOUNTING TREATMENT

The following table illustrates the stages and related processes of computer software development. These are used to identify the appropriate accounting treatment - Capital or Expense – depending on the types of activity occurring during a project. Discussion of various types of activities within each stage follows the table to provide further guidance.

Preliminary Project Stage Accounting Treatment – **Expense**	*Application Development Stage* Accounting Treatment – **Capital**	*Implementation/Operation Stage* Accounting Treatment – **Capital/Expense**
Planning Feasibility or Consulting Study Business Process Redesign Requirement Analysis	Design Construction/Coding Testing, including parallel processing phase	Implementation Training Application maintenance Modifications to another system

PRELIMINARY PROJECT STAGE

1. Planning – Work performed to identify business direction and needs, then to develop a system or technology plan:

    - Providing clear understanding of an organization's goals and objectives under the current business environment.
    - Preparing architecture for leveraging information technology to meet goals and objectives.
    - Developing multi-year information systems/technology plans.
    - Planning for Disaster Recovery and associated Contingency plans.

Accounting Treatment - Expense

2. Feasibility or Consulting Study – Work to study, analyze, or evaluate current practices, processes, or procedures in order to determine what, if anything needs to change.

   - Identifying strengths and weaknesses of current operations and information systems.
   - Conducting a feasibility study to identify probable costs and benefits of some action.
   - Assessing performance levels.
   - Determining project scope and boundaries for potential projects (i.e., identifying business processes or functional areas to be included, excluded, or altered).
   - Identifying problems/opportunities needing immediate action.
   - Invite vendors to perform demonstrations of how software will fulfill needs.
   - Select a consultant to assist in the development or installation of the software.

Accounting Treatment - Expense

3. Business Process Redesign – Used in business areas where it is believe there are significant opportunities for improving work processes before system development activities begin. Activities included:
   - Documenting "current state" business processes in detail.
   - Collecting process performance attributes such as cycle time, resources consumed, work volumes, and processing efficiency.
   - Conducting value and/or root cause analysis.
   - Designing "future state" processes.
   - Defining information models and technology enablers.
   - Developing detailed cost-benefit analyses

If this step is skipped, a slightly modified version of these activities is performed in the Requirements Analysis stage. The need for an information system is validated and often further defined upon the completion of this stage.

Accounting Treatment - Expense

4. Requirements Analysis - Once it is determined that existing software needs to be changed or new software acquired by construction or package acquisition, information system requirements are gathered. Activities include:

   - Identifying key business/information requirements. May include steps to document current/future processes, evaluate performance attributes, and perform value analysis on processes if a business process analysis was not performed.
   - Developing a conceptual design for the new system.
   - Sending Requests for Proposals (RFPs) to vendors.

- Evaluating software packaged-based solutions to determine whether to purchase or design a system.
- Finalizing the cost - benefit analysis.
- Determine that the technology needed exists.
- Explore alternative means of achieving performance requirements, (i.e. should the software be purchased or built, should the software run on mainframe or a client server?)

Accounting Treatment - Expense

The actions in the Preliminary Project stage may be performed in a different order than described, but most do occur at some level at the start of a project.

At the completion of the Requirements Analysis step, the scope and technical feasibility of the specific system to be developed will be clarified, and costs can be estimated with a high degree of certainty.

Capitalization of costs will begin when the Preliminary Requirements are completed, and management commits to funding the project, and that it is probable that the project will be completed and the software will be used to perform the function intended. For capital projects, a **Project Profile** and associated requirements are necessary for approval.

APPLICATION DEVELOPMENT STAGE

1. Design (Specific) – Includes design of technical components of the new system, and development of plans for construction and testing. Specifications for software and hardware components are developed, and products acquired/installed.

2. Construction and Testing – Costs to build/program the system, conduct various tests to ensure system integrity, and to develop training and implementation plans.

   Capitalized costs included in these stages include:

   - External direct costs of materials and services – contract labor, software purchased to support construction of application, materials, services, travel expenses incurred by employees as part of their job directly associated to the development.
   - Operating Area Labor – Operating area employees (non-IT) assisting with a project should charge normal operating accounts unless time on a project is expected to exceed 3 months.

Capitalization ends when the software is substantially complete and ready to be placed into service – classified as "used and useful".

When it becomes probable that the software project will not be completed and place into service, no further costs will be capitalized.

IMPLEMENTATION/OPERATION STAGE

1. Implementation – Activities to bring the system in to production where it is "used and useful":

    a. Data Conversion – Costs to build or acquire software to convert automated/electronic data.
    b. Interface Programming – Costs to construct interfaces between the new and existing systems.
    c. Programming of System Reports – Costs to develop new or rebuild existing reports from data in the new system.

    Accounting Treatment:
    Before System is Operational – Capital
    After System is Operational – Expense

    d. Data Conversion – Activities to process/convert data from an existing system into the new system.

    Accounting Treatment – Expense

2. Training – Planning, developing, and delivering training to operators on the use of the new system (trainer costs).

    Accounting Treatment:
    Before System is Operational – Capital
    After System is Operational – Expense

    Operator or client time to attend training on how to use the new system (trainee costs).

    Accounting Treatment – Expense

3. Application Maintenance – Costs of an annual maintenance agreement for the new system.

    Accounting Treatment – Expense

    Over life of the agreement

4. Modifications to Another System – Costs to modify other systems due to the development of the new system.

   Accounting Treatment – Expense
   Unless it meets the guidelines above for meeting capital treatment as an enhancement or increase in functionality.

RELATED PROJECT ACTIVITIES

Data Creation – Costs to create data not currently available in an electronic version are charged to expense.

Data Cleanup – Costs to edit or otherwise clean up existing data for accuracy in order to make it more functional is expensed.

Costs After System is Operational – Once a system is "used and useful" for its intended purpose, subsequent costs are expensed unless they meet the guidelines above for capitalization as functional enhancement. Includes the phasing in of a system over an extended period of time or in multiple locations/sites.

Interpretation Guidance regarding software implementations

1. If, as part of a software implementation, a vendor is brought onsite and shows project team members various aspects of the system (software), can this be capitalized? Does it matter if the vendor comes here or if we go to them?

   When the project team is working with the vendor in these sessions primarily on how we will design the system, then these session costs can be capitalized. When these sessions primarily involve training, such as learning the system functionality in order to provide future support of the system or how to use the system to migrate into production, then these session costs are to be expensed.

   It doesn't matter whether these discussions occur at a PGE location or a vendor location. The activity/purpose behind the sessions determines the accounting.

2. Does the software implementation methodology used impact what costs can be capitalized?

   No, it does not matter what methodology or approach is used. Whether full system development and implementation cycles occur in smaller groupings or larger work efforts, only the design, development and testing activities can be capitalized. Planning activities, administrative support of the project, change management, business process/efficiency activities, data conversion, system-user training and end-user training are always to be expensed.

3. If a software contract for services to implement software is not broken out by activities, how do I figure out what is capitalized and what is expensed?

   The project manager/sponsoring manager is responsible for determining reasonable and supportable percentages to allocate costs and ensuring such percentages are then used when assigning accounting for budgeting, forecasting and coding vendor invoices. The percentage allocation should be reviewed with an Asset Accounting analyst. For example:

   A software implementation services contract is for $1 million. Services include assessment activities, design, build, data conversion, testing, management status discussion, communication support, business process change management support, system administration training and end-user training.

   Assessment Activities: 20% (Expense)
   Design, Build Activities: 50% (Capital)
   Data Conversion: 10% (Expense)
   Administrative and business process activities: 10% (Expense)
   System Administration training: 5% (Expense)
   End-User training: 5% (Expense)

Software Capital Criteria- APPD 4-400-01, ASC 350-40 (formerly SOP 98-1), ASU 2015-05

Questions - contact Preston Martin. x7460

1) Asset life is greater than 1 year
2) Creates a new or replaces an existing asset or Enhances existing asset (significantly extends life, alters use, change in functionality)
3) Direct Costs of Software Development > $250,000
4) Hosted Services are accounted for as Expense as this is a service agreement - not an "owned" asset by PGE
5) After a system is operational, the purchase of additional licenses must meet the same capitalization criteria: Asset life is greater than 1 year & Software Specific Capital Criteria (> $250,000)

Preliminary Stage (Expense)	Application Development (Capital)	Implementation & Operation (Capital or Expense)
Planning - work performed to identify business direction and needs, then to develop a system or technology plan * defining goals & objectives * developing multi-year IT plans * planning disaster recovery & contingency plans **Feasibility or consulting studies** - work to study, analyze, or evaluate current practices, processes or procedures in * probable costs and benefits studies * assessing performance levels * conceptual formulation of alternatives * evaluation of alternatives * determination of needed technology * determining project scope **Business process design / redesign** * documenting current state * collecting process performance attributes * conducting value or root cause analysis * designing future state processes * defining information models and technology enablers * developing cost/benefit analyses **Requirement analysis & final selection of alternatives** * Identify key business / information requirements * Develop conceptual design for new system * Sending RFPs to vendors * Evaluation of software packages to determine whether to purchase, design, or both * Finalize cost / benefit analysis	**Technical design** * software configuration and software interfaces * design of technical components * development of plans for construction and testing * specifications for HW and SW components **Product Acquisition & Installation** * installation to hardware * construction/coding including building interfaces * software to convert electronic data or support construction of the application * develop and build reports * direct costs of materials and services & contract labor * travel expenses incurred by employees as part of their job directly associated to the development * Operating area labor (non-IT) working on the project for more than 3 months (< 3 months should charge normal operating accounts) **Testing** * system integrity * parallel processing phase **Project Management** - only if employee is dedicated full-time to the project for 3 months or more **Training** - costs of employee(s) while observing / assisting with configuration. Costs to develop user manuals.	**Before System is Operational - CAPITAL** **After System is Operational - EXPENSE** * Costs to build or acquire software to convert data * Interface programming * Programming of system reports * Training - costs of employee(s) while observing / assisting with configuration. Costs to develop user manuals. **EXPENSE** * Training (except as noted above) * Modifications to other systems * Software Maintenance * Data Conversion * Data creation & data cleanup * Cloud computing arrangements include software as a service (SaaS), platform as a service, infrastructure as a service, and other similar hosting arrangements (this is always an expense, the company does not own the asset)

NOTES:
1) Project Managers can split time between capital projects and still be capitalized. If part of their time is O&M, then expense all.
2) Staff time should not be capitalized unless the staff is dedicated to the project and performing a capitalizable activity.

April 5, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 296
Dated March 22, 2017

Request:

Please provide a worksheet showing all costs PGE includes in revenue requirement for the 2018 test year that represent the Preliminary Project Phase of any computer software or IT project. Please list dollar amounts by project, amount capitalized, amount expensed, labor and non-labor.

Response:

Preliminary costs are expensed per accounting and GAAP guidance. These preliminary costs include the investigative stage of any software project (e.g., planning, feasibility analysis, business design and requirements analysis, etc.). Please see PGE's response to OPUC Data Request No. 295 which provides PGE's accounting policies on software.

PGE tracks costs separately for larger, unique initiatives, such as CET, but we do not do so for all IT projects. In addition, we do not separately track preliminary costs from post-deployment O&M. PGE's tracks costs by project, activity, or system by means of Accounting Work Orders (AWOs). After a discussion with OPUC Staff, PGE is providing IT service provider costs in Account 1840004 (i.e., allocated IT O&M costs) with the detail sorted and summed by AWOs. Please see PGE's response OPUC Data Request No. 309, Attachment 309-A.

April 5, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 309
Dated March 23, 2017

Request:

Please provide in an excel sheet a breakdown by year and by FERC Account of IT O&M expenses related to the maintenance of existing systems and the costs related to new projects for the years 2014, 2015 and 2016.

Response:

PGE objects to this request on the basis that it is vague and ambiguous. PGE made several unsuccessful attempts to contact the OPUC Staff (email and telephone) to clarify this request and discuss what information we could provide that would assist Staff in their review. Without waiving this objection and absent clarification, PGE responds as follows:

PGE does not differentiate between new and existing systems. Attachment 309-A lists IT service provider cost data (i.e., allocated IT O&M costs) sorted and summed by accounting work order (AWO), department, and cost element; it also shows IT direct charges sorted and summed by AWO. The AWO is PGE's method to track costs associated with activities, projects, and systems.

UE 319

Attachment 309-A

Provided in Electronic Format only

IT Projects by Accounting Work Order

April 6, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 312
Dated March 23, 2017

Request:

Please provide an explanation on how you determine whether a storm is a level 3 or not and did any of the 3 storms that occurred in 2016 result in additional capital expenditure?

Response:

Level 3 storms are determined by any of the following system impact criteria:

- Multiple substations and feeders out of service;
- Greater than 50,000 customers out of service;
- Three or four regions are experiencing outages;
- Greater than 72 hours to restore service; or
- Outside assistance may be required.

PGE experienced two level 3storms in 2016. PGE conducted capital work through pole replacements in both 2016 storms. These pole replacement costs are charged to capital and are not applied against the storm reserve established in UE 215. See Attachment 312-A for capital expenditures from the two level 3 storms in 2016.

Attachment 312-A, is protected information subject to Protective Order No 17-057.

UE 319

Attachment 312-A

Provided in Electronic Format only

Protected Information Subject to Protective Order No. 17-057

Capital Expenditures for Level 3 Storms in 2016

April 6, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 313
Dated March 23, 2017

Request:

Please provide all transactional details in excel format of the costs incurred for the 2016 storm damages including vendor names, transaction and invoice details along with the following fields:

Operating Unit
Operating Unit Description
Account
Account Description
Dept Id
Dept ID Description
Cost Elm
Cost Elm Description
2014 Actuals
2015 Actuals
2016 Actuals
2017 Budget
2018 Forecast
FERC
Labor/Non-Labor
CE Source
Utility/Non-Utility

Response:

Attachment 313-A provides the requested transaction detail for costs related to 2016 storms. This file includes 2017 costs associated with 2016 storms because some storm costs near year-end of 2016 were processed in early 2017.

Please note that Attachment 313-A includes all storm costs. When PGE determines that restoration costs are covered by the storm reserve, however, certain costs are excluded from the reserve account (e.g., straight time labor and associated labor loadings) because they are already included in base rates. As stated in PGE's response to OPUC Data Request No. 312, any capital-related storm restoration costs are also excluded from the reserve account.

Attachment 313-A, is protected information subject to Protective Order No 17-057.

UE 319

Attachment 313-A

Provided in Electronic Format only

Protected Information Subject to Protective Order No. 17-057

2016 Storm Cost Transactional Details

April 12, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 407
Dated March 29, 2017

Request:

Referring to UE 319 / PGE / 200 Tooman – Brown / 14 at 17, please justify the Company's proposed working cash rate of 3.638 percent. In the response, please:

a. **Explain how and when the rate was derived and why it is still relevant for calculating the 2018 test year forecasted working capital;**
b. **Explain when the Company plans to do a new lead/lag study, or update the current lead lag study;**
c. **Explain whether any of the Company's new programs, such as the Fee Free Bank Card program, have impacted the lead/lag time related to accounts receivable/revenues;**
d. **Explain whether any of the software systems the Company is currently implementing in 2017 or has implemented in the last four years have impacted the lead/lag time related to operating expenses, accounts payable, and inventory levels. In the response, specifically address whether the improvements to the Maximo system has resulted in improved cash management and reductions in working capital;**
e. **Explain the Company's methodology used to measure, track, monitor and report working capital metrics. In the response, please:**
    i. **List the type of metrics tracked, and the rationale for tracking each metric.**
    ii. **Provide the baseline for each metric, e.g. current performance against target or past performance, peer group benchmark etc.;**
    iii. **The types of reports, e.g. Working Capital Dashboard, generated for management review and the timing of each report, e.g. daily, weekly, monthly, quarterly, annually; and,**
    iv. **For each of the last four years, 2016, 2015, 2014, 2013, please provide an annual report provided to the CFO and other executive management for the purposes of evaluating working capital management and identifying corrective or prospective actions.**

Response:

a. The working cash factor included in the 2018 general rate case is the same rate as was used in PGE's 2016 general rate case. The rate included in the 2016 and 2018 general rate cases is 3.628%. There have been no significant changes impacting working cash since PGE's last general rate case, and, therefore, PGE feels this rate continues to be relevant.

b. PGE updated its lead/lag model in the third quarter of 2016. The update resulted in a value of 3.789%, which is slightly higher than the previously approved rate of 3.628%. Given the closeness of the rates, PGE elected to continue using the rate previously approved by Commission Order 15-356. PGE expects to update its lead/lag model in the next general rate case.

c. New programs, including the Fee Free Bank Card (FFBC) do not appear to have materially impacted lead/lag times as it relates to the collection of revenues. As shown in Attachment 407-A, day sales outstanding (DSO), which measures the number of days it has taken to collect revenue after electric sales have been billed, has remained relatively stable over the 2013-2016 time period.

d. PGE has not seen noticeable changes in lead/lag times as a result of software system implementations in the past four years and does not anticipate significant changes in lead/lag times as the result of any system implementation or upgrades in 2017. Maximo, specifically, has resulted in the improvement of tracking work orders, but not in a reduction of lead/lag times related to inventory. Inventories included in the lead/lag study are gas and coal fuel, which are not impacted by Maximo.

e. PGE regularly tracks DSO (see part c, above), which measures the average number of days it has taken to collect revenue after electric sales have been billed. PGE monitors this metric in order to identify and mitigate collection issues. This report tracks PGE's current outstanding receivables against current revenues over the number of days in the period and compares current quarterly and annual DSOs to prior quarterly and annual DSOs. PGE management receives this report on a quarterly basis. Attachment 407-A provides this report from 2013 through 2016.

   Additionally, PGE will review payment terms with suppliers in an effort to move suppliers to more favorable payment terms to benefit working capital. While review of these terms occurs periodically, there is currently no systematic tracking of this metric or reporting of it to senior management.

UE 319

Attachment 407-A

Provided in Electronic Format only

Day Sales Outstanding; 2013-2016

April 19, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 425
Dated April 5, 2017

Request:

Referring to the Company's Excel workpaper, "Total Compensation.xlsx", please supplement and add a column with the compensation details for the 37.91 FTE included in the Company's proposed CET deferral. (See the Company's Excel workpaper, "2014-2018_FTE_W&W_By Operation, RC & Class_01-30-17.xlsx", for CET FTE.) Additionally, please provide the total compensation data for each of the years 2012 and 2013 in an Excel worksheet in the same level of detail as provided in "Total Compensation.xlsx".

Response:

Please refer to the PGE Exhibit 400 work paper, 2014 – 2018_FTE_W&S_By Operation,RC & Class_01-30-17, worksheet, "By Operation", line 623 for the amount of CET program deferral-related wages and salaries costs removed from PGE's test year request. There are no other compensation-related costs associated with these FTEs. PGE's response to OPUC Data Request No. 299, Attachment 299-A provides 2012 and 2013 total compensation data.

April 19, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 429
Dated April 5, 2017

Request:

For each filed Federal tax return for the tax years 2012 – 2015, inclusive, please provide:

a. **The cost of plant additions eligible for bonus depreciation;**
b. **The maximum amount of bonus depreciation deduction available;**
c. **The cost of plant additions for which bonus depreciation was actually elected; and,**
d. **The actual amount of bonus depreciation deducted; and,**
e. **A narrative explaining the Company's rationale or tax strategy regarding the amount of actual bonus depreciation deducted for each of the above mentioned tax years.**

Response:

For each filed federal tax return for the tax years 2012 to 2015, inclusive:

a. Attachment 429-A, which is protected and subject to Protective Order No. 17-057, provides the tax cost of plant additions eligible for bonus depreciation for the years 2012-2015.

b. Attachment 429-B, which is protected and subject to Protective Order No. 17-057, provides the maximum amount of bonus depreciation deduction available for the years 2012-2015.

c. PGE elected not to claim bonus depreciation on the federal tax returns filed in the tax years 2012 to 2015, inclusive.

d. There was no bonus depreciation deducted on the federal tax returns filed in the tax years 2012 to 2015, inclusive.

e. The reasons for electing to not claim bonus depreciation on the federal tax returns filed in the tax years 2012 to 2015 were:

1. The calculation of tax depreciation for Oregon excise tax purposes conforms to the federal calculation of tax depreciation. Claiming bonus depreciation would reduce the Oregon excise tax liability and thus reduce the amount of state tax credits utilized. If bonus depreciation were claimed in these years, there was the potential to lose the permanent tax credit benefit as they would expire before they could be utilized. Oregon credits expire within 3 to 8 years of the year generated.

   Another permanent benefit that is affected by bonus depreciation is the Domestic Production Activities Deduction (Internal Revenue Code §199). When depreciation is increased, the Domestic Production Activities Deduction is reduced or eliminated. The Domestic Production Activities deduction is estimated to be a $9 million tax deduction in this rate case.

2. The other permanent benefit that would, at a minimum, be deferred is the federal Production Tax Credit (PTC). Customers receive the benefit of PTCs based on forecasted generation. For PGE, the benefit is deferred until the PTCs are utilized to reduce the current tax liability. Therefore, unutilized PTCs create a deferred tax asset.
   i. An increase in the unutilized PTC balance will increase rate base. IRS normalization rules require that deferred tax assets that are caused by accelerated depreciation must be included in rate base.
   ii. Unknown future tax code changes may eliminate PGEs ability to utilize this permanent benefit. In order to reduce this exposure to a permanent loss of PTC benefit, PGE has chosen to postpone the temporary benefit from bonus depreciation.

UE 319

Attachment 429-A

Provided in Electronic Format only

Protected Information Subject to Protective Order No. 17-057

Bonus Depreciation

UE 319

Attachment 429-B

Provided in Electronic Format only

Protected Information Subject to Protective Order No. 17-057

Bonus Depreciation

April 19, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 430
Dated April 5, 2017

Request:

Please explain whether any of the 2016 plant additions and the 2017 forecasted plant additions included the UE 319 rate bate are eligible for bonus depreciation. If so, for each year please provide:

a. **The cost of the plant additions eligible for bonus depreciation;**
b. **The amount of bonus depreciation deduction available; and,**
c. **The amount of related ADIT.**

If the Company did not include in its 2018 test year ADIT a calculation of deferred income taxes related to bonus depreciation for 2016 plant additions or for 2017 forecasted plant additions, please provide a detailed explanation of the Company's rationale.

Response:

A portion of the estimated tax basis of plant additions for 2016 and 2017 included in UE 319 could be eligible for bonus depreciation.

a. Attachment 430-A, which is protected and subject to Protective Order No. 17-057, provides the estimated tax cost of plant additions eligible for bonus depreciation.

b. Attachment 430-B, which is protected and subject to Protective Order No. 17-057, provides the bonus depreciation deduction available assuming PGE utilizes the estimated tax basis additions for 2016 and 2017.

c. PGE did not claim bonus depreciation for the estimated 2016 or 2017 plant additions included in the UE 319 rate base. Due to the reasons given in PGE's response to OPUC Data Request No. 429, part (e), PGE believes that it is not in the best interest of its customers to claim bonus depreciation in this rate case. Therefore, no ADIT was calculated for bonus depreciation. Attachment 430-C, which is protected and subject to Protective Order No. 17-057, provides the estimated ADIT liability for 2016 and 2017, if bonus depreciation had been claimed.

UE 319

Attachment 430-A

Provided in Electronic Format only

Protected Information Subject to Protective Order No. 17-057

UE 319

Attachment 430-B

Provided in Electronic Format only

Protected Information Subject to Protective Order No. 17-057

UE 319

Attachment 430-C

Provided in Electronic Format only

Protected Information Subject to Protective Order No. 17-057

April 25, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 469
Dated April 11, 2017

Request:

Referring to UE 319/PGE/200, Tooman-Brown/3 and the Company's response to Staff DR 164 please provide a detailed calculation of the Company's escalation adjustment to the 2017 budget in an Excel spreadsheet to cost elements (CE) 1502, 1602, 2200, 2300, 2101, 2110, 2400, and 2701. Please exclude all labor and include the FERC account, FERC account description, CE number, CE description, 2017 budget prior to escalation, escalation factor, and 2017 budgeted amounts after escalation. The 2017 budgeted amount should be consistent with the 2017 budgeted amounts provided in the Company's Exhibit Support 2018.xlsx, tab IS-GRC-QRY and OPUC_DR_164_Attach A.xlsx and the rows of data should be highlighted consistent with the aforementioned Excel files.

Response:

For purposes of applying base escalation to specific non-labor and non-PGE labor cost elements, PGE relied on Global Insight's (GI) August 2016 short-term economic forecast. Attachment 469-A provides the cost element-specific annualized base rates used to escalate 2017 budget amounts to PGE's 2018 forecast and a description of the GI source used. As described in PGE Exhibit 400, PGE bases its labor escalation rate on industry and overall labor market data (page 15). Please note that these escalation factors are some of numerous factors creating differences from 2016 to 2018 and are not separably identifiable in PGE's accounting system. Examples of other factors contributing to year-to-year variances include quantity changes, project/scope changes, FTE changes, contract/service agreement changes, and other known and measurable changes.

Attachment 469-A is protected information and subject to Protective Order No. 17-057.

UE 319

Attachment 469-A

Provided in Electronic Format only

Protected Information Subject to Protective Order No. 17-057

2017-2018 Escalation Rates

April 25, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 470
Dated April 11, 2017

Request:

Referring to UE 319/PGE/200, Tooman-Brown/3 at 11-17 and the above Staff DR No. 469, for each escalation rate calculated or utilized, please provide a justification of the appropriateness of the rate, copies of the original source documents that support the Company's position, and the Company's rationale for using each escalation rate based on account attributes such as CE number or CE type.

Response:

See PGE's response to OPUC Data Request No. 469.

June 9, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 644
Dated June 1, 2017

Request:

Please explain why the rate for OPUC Fees used in the Company's calculation of the 2018 test year OPUC fees and for its revenue sensitive cost (see UE 319/PGE/201, Tooman-Brown/3) is 0.375 percent when the maximum rate the Commission is allowed to levy is 0.300 percent per ORS 756.310. Additionally, please see Commission order 17-065 granting an increase from 0.275 percent to 0.300 percent for the most recent annual fee charge.

Response:

The calculation is based on the current definition of gross revenue for OPUC fee purposes, which is 0.30% of retail revenue and 0.30% of wholesale revenues but the latter revenues are capped at 25% of retail revenues. Hence, we take 0.30% of retail revenues and add 25% of 0.30% for wholesale revenues, which produces the 0.3750% rate in the revenue requirement. Although this assumption was valid during periods with lower PGE retail revenue and higher power prices, it had inadvertently not been updated with the most recent change in the OPUC fee. To correct this, the average of the most recent three years of actual data produces an OPUC Fee Rate of 0.3211% as calculated in Attachment 644-A.

UE 319

Attachment 644-A

Provided in Electronic Format only

OPUC Fee Calculation

CASE: UE 319
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 406

Exhibits in Support
Of Opening Testimony

June 16, 2017

Exhibit 406 is confidential and

Is subject to Protective Order No.17-057

CASE: UE 319
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 500

Opening Testimony

June 16, 2017

Q. Please state your name, occupation, and business address.

A. My name is Matt Muldoon. I am a Senior Economist for the Public Utility Commission of Oregon (Commission or OPUC). My business address is: 201 High Street SE, Suite 100, Salem, OR 97301.

Q. Please describe your educational background and work experience.

A. My educational background and work experience are set forth in my Witness Qualification Statement, which is provided as Exhibit Staff/501.

Q. What is the purpose of your testimony?

A. I am responsible for five issues in this docket:

<u>Cost of Capital</u>

1. Capital Structure;
2. Cost of Common Equity, also known as Return on Equity (ROE);
3. Cost of Long-Term (LT) Debt;

<u>Post-Retirement Expense</u>

4. Pension and Other Post Retirement Expenses; and
5. Allowance for Funds Used During Construction (AFUDC).

Q. What is your summary recommendation?

A. I recommend a 49.5 percent equity and 50.5 percent LT Debt Capital Structure, a Portland General Electric Company (PGE or Company) ROE of 9.2 percent within a range of most reasonable ROEs of 9.0 to 9.3 percent, and a 4.852 percent Cost of LT Debt. This generates an overall authorized Rate of Return (ROR) of 7.004 percent.

Q. Did you prepare tables showing current, PGE-proposed and Staff recommended overall Cost of Capital (CoC)?

A. Yes, the following three tables provide that information.

Table 1

PGE Current OPUC Authorized (UE 294 Order No. 15-356)			Now
Component	Percent of Total	Stipulated or Implied Cost	Weighted Average
Long Term Debt	50.00%	5.350%	2.675%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	50.00%	9.60%	4.800%
	100.00%		7.475%

Table 2

PGE Requested – UE 319		PGE Direct Testimony		
Component	Percent of Total	Cost	Weighted Average	ROR vs. Current
Long Term Debt	50.00%	5.170%	2.585%	-0.015%
Preferred Stock	0.00%		0.000%	
Common Stock	50.00%	9.75%	4.875%	
	100.00%		7.460%	

Table 3

Staff Proposed – UG 319		Opening Testimony		
Component	Percent of Total	Cost	Weighted Average	ROR vs. Current
Long Term Debt	50.5%	4.852%	2.450%	-0.471%
Preferred Stock	0.00%		0.000%	
Common Stock	49.5%	9.2%	4.554%	
	100.00%		7.004%	

Q. Have you issued data requests (DRs) in this rate case?

A. Yes. My analysis is informed by the Company's responses to 116 multipart DRs, some of which are open ended or also required updates.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Did you prepare exhibits in support of your opening testimony?

A. Yes. I prepared the following exhibits:

ISSUE 1 – CAPITAL STRUCTURE (S-13)

Q. What is the basis for your recommendation for a capital structure of 49.5 percent equity and 50.5 percent LT Debt?

A. I have four reasons for supporting my recommended capital structure:

1. This is my best estimate of the average capital structure over the test year, concluding at the end of December 2018;
2. This capital structure is within the range that optimizes the Company's financial performance balanced against the risk of leverage;
3. This capital structure excludes elements not historically considered LT Debt by the Commission such as short-term and imputed debt; and
4. Value Line (VL) projects PGE will have this capital structure on average from calendar years 2017 through 2021.

Q. Is using a Capital Structure different than 50/50 a departure from recent dockets for PGE?

A. Yes. Staff has recommended a 50/50 Capital Structure in recent general rate cases for PGE. The Company has fluctuated around the above target year-to-year in the past. But, based on public information PGE is now trending toward more debt than equity. That is not unreasonable given the continued low cost of LT Debt in comparison to equity.

Q. Have you any cautions regarding your projection of Capital Structure?

A. Yes, I could change my recommendation if new information comes to light. There are two primary causes for caution in considering my recommendation.

First, PGE's stock is near all-time highs. Were the Company planning to issue new equity or to decide to enter into an equity-forward, this would not yet be public information. Second, PGE's capital spending plans may be in flux, potentially causing changes to planned LT Debt issuances through and near the test period.

ISSUE 2 – COST OF COMMON EQUITY (ROE) (S-13)

Q. What are the primary reasons for the difference between the Company's requested 9.75 percent point ROE and your recommended 9.2 percent point ROE?

A. The Company:

- Relies on the constant growth — single stage — Discounted Cash Flow (DCF) model of Professor Myron J. Gordon. This model is based on an assumption of a constant level of growth that does not take into account actual growth forecasts. PGE's reliance on this model has boosted PGE's projected ROE. Importantly, the Commission has given this model no weight in recent general rate cases, rejecting the idea that it is reasonable to rely on a model that uses a constant growth rate.[1]
- Relies on the "Empirical CAPM" or (ECAPM) model that has not historically been used by the Commission. The ECAPM Model presumes that the security market line could be pivoted at a designated point until a reasonable result is obtained. The argument is that a properly pivoted CAPM model will correct for CAPM's flaws. Essentially this model augments its CAPM ROE by a minimum of 50 bps.
- Uses a different peer screen than Staff. Staff sensitivity modeling shows highest ROE results when the Company's peer group was used in Staff's models.
- Uses some higher modeling inputs than Staff. For example, for CAPM inputs, the Company uses a higher market risk premium and a higher risk free rate.

Q. Does your recommended ROE meet appropriate standards?

A. Yes. The 9.2 percent ROE I recommend meets the *Hope* and *Bluefield* standards, as well as the requirements of Oregon Revised Statute (ORS) 756.040. My recommendations are consistent with establishing "fair and reasonable rates" that are both "commensurate with the return on

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1 *In the Matter of Portland General Electric*, OPUC Docket UE 115, Order No. 01-777 at 27, 37; (August 31, 2001); *In the Matter of PacifiCorp*, OPUC Docket UE 116, Order No. 01-787 at 24 (September 7, 2001); *In the Matter of Northwest Natural Gas Company*, OPUC Docket UG 221, OPUC Order No. 12-437 at 6 (November 16, 2012).

investments in other enterprises having corresponding risks" and "sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital."[2]

Q. Are these the same standards discussed in PGE's testimony?

A. Yes. Staff and PGE apply the same legal standards. However, PGE and Staff disagree on what ROE is commensurate with that of other utilities and other investment opportunities with risk exposure similar to PGE's. When investors' expected rate of return is measured using a reasonable expectation of long-term growth, and when risk is measured using an appropriate peer group of utilities, the resulting ROE is within the range recommended by Staff.

CONSIDERATIONS IN THIS RATE CASE

Q. What are economic/financial trends or considerations that inform your analysis?

A. First, projections of long-term growth rates by a broad consensus of U.S. Government, academic, business and analytic referent sources for U.S. gross domestic product (GDP) remain low. In fact, the non-partisan Congressional Budget Office (CBO) has lowered their long-term growth projections. In contrast the new U.S. President in his "Blueprint" and initial budget says that he will restore U.S. growth to long-run trends. Many financial professionals are skeptical that there is a solid factual basis behind white house projections of three to four percent persistent long-term GDP growth.[3]

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2 *See* ORS 756.040(1)(a) and (b).

3 *See* Winners and Losers in the Proposed Budget in Staff/210 Muldoon/109 for more detail on how this latest white house budget departs from historic trends.

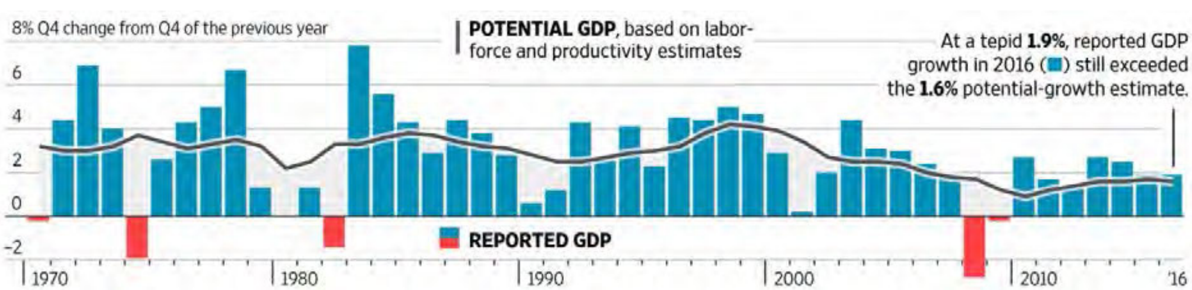
Another consideration is that investor flight to quality persists. A pivot away from U.S. utility securities toward manufacturing and financials after the November 2016 national election was short-lived. Persistent global worries and low global fixed income yields mixed with new uncertainties repeatedly caused many investors to seek safety in the LT Debt and Common Stock of U.S. regulated utilities.[4]

Q. Discuss your first consideration, regarding growth rates.

A. Moody's Capital Markets Research, Inc., the Wall Street Journal (WSJ), and a variety of other business publications suggest that accelerating the U.S. economy back to historical long-run growth rates, while possible, requires certain inputs.

Figure 1[5]

U.S. Economy Returns to Lackluster Growth



The WSJ's assessment is that increasing the rate of U.S. GDP growth by 50 to 100 percent per year in the U.S. requires: more working Americans

4 *Also see* Staff/210 to get a sense of the persistent investor flight to quality / low risk.

5 Source: "Clearing a Low Bar", WSJ, Jan. 27, 2017.

bolstered by new investment in plant, equipment, and cutting-edge technologies to boost productivity. So far that has not happened.[6]

Q. Are you saying that accelerating the U.S. GDP Growth rate is harder than just issuing of a set of executive commands or publishing an aspirational budget?

A. Yes, for example, it is hard to reconcile how possible new immigration policies and declining birth rates noted in "The Economy's People Problem" cited above, translate soon to greater output growth.

Q. How Does the Wall Street Journal (WSJ) Summarize a Variety of Economic Analyses on This Topic?

A. The WSJ puts it straightforwardly as follows: "Two stubborn obstacles stand in [President Trump's] way. The work force isn't producing enough new workers, and the productivity of those working isn't growing fast enough. In the long term, an economy can't expand faster than the combined growth rates of its working population and their output per hour."[7]

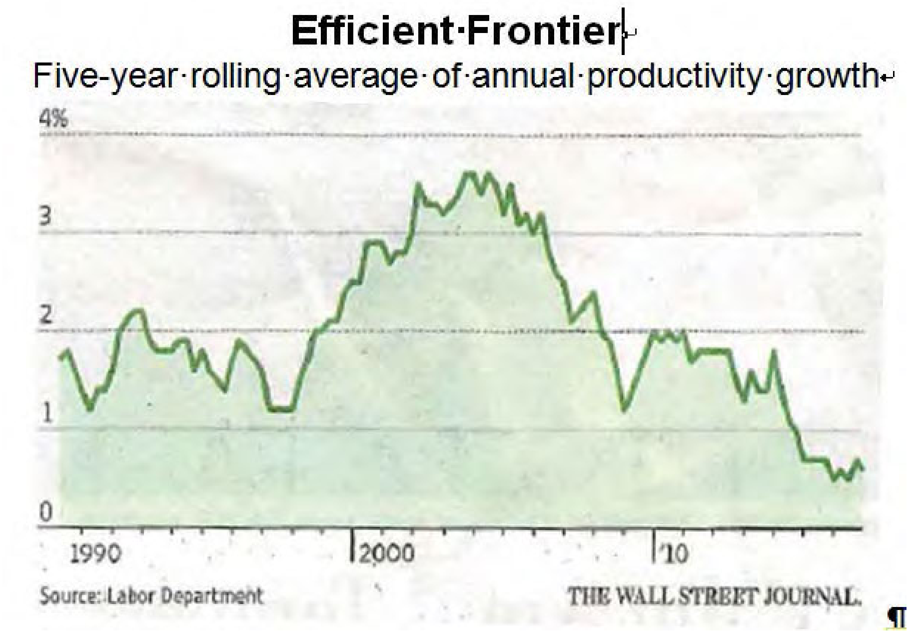
Q. Does the slow U.S. GDP growth impair PGE's ability to grow faster?

A. Yes, PGE is constrained by the growth of the economy in which it operates.

[6] *See* Justin Lahart, "The Economy's People Problem" WSJ, February 3, 2017.

[7] *See*: "Can Trump Deliver 3% Growth? Stubborn Realities Stand in the Way" in the May 15, 2017 WSJ.

Figure 2[8]



Q. Addressing your second topic, what is the relevance of temporary fixes for many recurring global financial issues amidst new political unrest and clashing national interests?

A. Rather than a momentary phase, each new global uncertainty such as British Exit from the European Union (BREXIT); upcoming French, Italian and Netherlands elections; U.S. political uncertainty and so on have investors snapping up U.S. treasuries and U.S. utility securities again.

Old concerns like declining Chinese growth with reduced imports and Greek debt jitters of a year ago reappear to mingle with new investor and U.S. Federal Reserve worries such as BREXIT, Italian debt, French debt and so

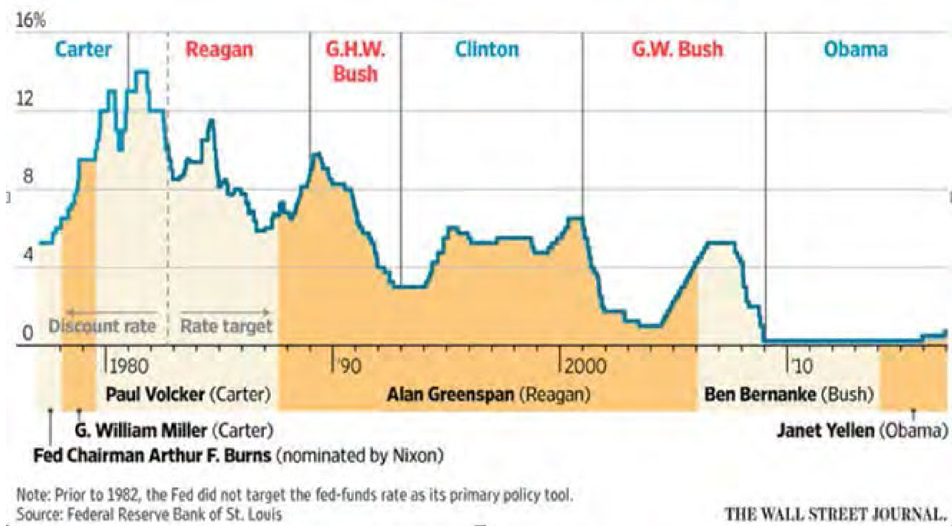
[8] Source: WSJ, January 3, 2017.

on.[9] This seeking of a safe harbor with highly certain returns is durable, suggesting that the demand for U.S. utility securities will remain high longer than in prior recoveries.[10]

Q. How have Federal Reserve Fund rates changed over time?

A. The WSJ provides a graph of Federal Reserve funds rate changes:[11]

Figure 3 — Fed Funds Rates



Q. How do the trends set forth above help or harm U.S. regulated utilities and PGE operations in particular?

A. Interest rates staying low longer increases demand for U.S. dividend-paying utility stocks. Demand for utility bonds remains strong, even in private placement markets. The U.S. Investor Owned Utility (IOU) combination of

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9 *See* Christopher Whittall, "Greek Bond Could Set Deadline on Country's Talks with Creditors", WSJ, February 10, 2017.

10 *See* Christopher Whittall and Ernese Bartha, "Ultra-long Debt Sells Despite Politics", WSJ, February 7, 2017.

11 *See* the January 27, 2017, WSJ "Federal Reserve Monitor — Market Data."

domestic U.S. sales and a strong dollar help provide these IOUs access to low cost capital.

Q. How do the trends discussed above affect PGE's CoC?

A. Continued investor flight to safety, and reduction in risk and regulatory lag, may merit a lower point ROE from within a range of reasonable ROEs than the uppermost reasonable ROE as discussed in the Avista general rate case.[12]

Q. Are current economic conditions excellent for energy utilities?

A. Yes, as discussed in my testimony in PGE's 2015 rate case, Docket No. UE 294, financial conditions are near optimal now for U.S. utilities.[13]

OVERVIEW OF ROE POSITIONS

Q. Describe the analysis underlying Staff's ROE recommendation.

A. I continue to rely primarily on two different three-stage "discounted cash flow" (DCF) models,[14] applied using a cohort group of peer utilities, to estimate the expected return on common equity required by PGE investors. I compare the results of my DCF analysis with electric utilities' authorized ROEs determined in 2016 rate cases as a check on the reasonableness of my ROE estimates.

Q. Describe the two DCF models that you used.

A. I continue to use models employed by Staff in prior cases that the Commission has adopted in ROE contested proceedings. My first model is a

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[12] Docket No. UG 288 Muldoon/200.

[13] Docket UG 288, Exhibit Staff/200, Muldoon/13.

[14] *See also* the Commission's discussion of multistage versus single-stage DCF models in Order No. 01-777 at page 27.

conventional three-stage Discounted Dividend Model, which Staff denotes as a “30-year Three-stage Discounted Dividend Model with Terminal Valuation based on Growing Perpetuity” (referred to as “Model X“). My second model is the “30-year Three-stage Discounted Dividend Model with Terminal Valuation Based on P/E Ratio” (referred to as “Model Y“).

Both models require, for each proxy company analyzed by Staff, a “current” market price per share of common stock, estimates of dividends per share to be received in the years 2017 through 2021, annual rates of dividend growth from 2022 through 2026, and a long-term growth rate applicable to dividends beyond 2026.

The three stages of the models are: 1) 2017-2021, where I use Value Line’s (VL) forecasts of dividends per share for each company; 2) 2022-2026, where the rate of dividend growth converges from the average rate over the 2017-2021 period to the growth rate in of the third stage; and 3) 2027-2046. This is the third “long-term” stage, for which growth rates are discussed.

Model X includes a terminal value calculation, in which I assume dividends per share grow indefinitely at the rate of growth in Stage 3 (“growing perpetuity”). In contrast, Model Y terminates in a sale of stock where the price is determined by my escalated price/earnings (P/E) ratio.

Q. Why did you use five years for Stages One and Two, and about 20 years for Stage Three?

A. A 30-year horizon is a reasonable modeling timeframe for investors consistent with previous Staff practices. This reflects investor consideration of 30-year U.S. Treasury (UST) Bond and alternate investment opportunities. I use five years for Stage One as that is the timeframe for which Value Line estimates of future dividends are reliable.[15] I use five years for Stage Two as that seems a reasonable length of time for individual companies' dividend growth rates that are materially different from the growth rate used in Stage Three (and common to all companies) to converge to a LT dividend growth rate more representative of all utilities. I discuss the mechanics of this convergence below. I use 20 years for Stage Three, corresponding to forward projections from federal sources, and calculate a terminal valuation for the sale of the Company's stock in 2045. These time periods for the three stages are the same as used by Staff in previous dockets in which the Commission relied on Staff's Multi-Stage DCF model.

Q. How do you address dividend timing?

A. Each model uses two sets of calculations that differ in the assumed timing of dividend receipt. One set of calculations is based on the standard assumption that the investor receives dividends at the end of each period.

The second set of calculations assumes the investor receives dividends at the beginning of each period. Each model averages the unadjusted ROE values to generate an Internal Rate of Return (IRR) produced with each set of calculations for each peer utility. This approach accounts for the time value of money, closely replicating actual quarterly receipt of dividends by investors.

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[15] Note: Value Line only makes projections five years into the future.

Q. What accounts for differences in peer capital structures?

A. Each model employs the Hamada equation[16] to calculate an adjustment for differences in capital structure between each peer utility and the PGE-proposed and Staff-assumed capital structure for PGE.[17] When few peer utilities are available, the Hamada equation ensures Staff's analysis addresses differences in peer utility capital structures.

Q. Does PGE use a different variant of the Hamada equations in the Company's modeling?

A. Yes, and I appreciate PGE's analysis in this regard. Staff and the Company are addressing like issues with similar thinking. Though PGE and Staff may not agree, they are both in the same sporting arena.

Q. What price do you use for each peer utility's stock?

A. I use the average of closing prices for each utility from the first trading day in January, February, and March 2017 to represent a reasonable snapshot of 2017, Q1.

Q. How do Staff's two DCF models differ?

A. Model X uses the calculation of a growing perpetuity as part of the terminal valuation in 2046. This may be the most common approach used in three-stage DCF models.

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16 Dr. Robert Hamada's Equation as used in Staff/202, Muldoon/4 separates the financial risk of a levered firm, represented by its mix of common stock, preferred stock, and debt, from its fundamental business risk. Staff corrects its ROE modeling for divergent amounts of debt, also referred to as leverage, between the Company and its peers.

17 Staff describes this adjustment in previous cost of capital testimony. *See*, as an example, Staff's description in Docket No. UE 233 Exhibit Staff/800, Storm/54-57.

Model Y uses the current price-earnings (P/E) ratio[18] multiplied by the estimated "earnings per share" (EPS) in 2047, which establishes the stock's "selling price" in 2046 for terminal valuation. I estimate the 2047 EPS analogously with methods used to estimate the 2046 dividend in both models; i.e., based on VL estimates to which multiple growth rates are sequentially applied.

Q. What is the purpose of Model Y?

A. I followed Staff's practice in recent rate cases of including this model as a method by which to incorporate the fact that most companies have estimates of future EPS and future dividends growing at different rates. Utilizing EPS that grows on a separate trajectory than dividends is the foundation for an alternative means of terminal valuation.[19]

Q. Do you process the Company's peer group through your models?

A. Yes. Staff peer screening identified six utilities with multiple attributes very close to PGE's. The Company's screening method identified 25 utilities reasonably similar to PGE. While Staff prefers its smaller more targeted peer group, Staff ran the larger PGE peer set through its modeling as a sensitivity study. Staff also ran a subset of Staff's peer group restricted to mid-capitalization size like PGE to make sure Staff's results were not biased because of the this factor.

[18] "Current" in this context means the price obtained, as previously described, divided by VL's estimated EPS; i.e., it is a forward P/E, not an historical P/E.

[19] Please note that the approach used in this second model is not the same as using a singular estimate of the growth rate in EPS as the growth rate in dividends.

Q. What other checks do you perform on your estimates?

A. I also calculate Capital Asset Pricing Model (CAPM) results for Staff's peer group and the Company's peer group.

PEER SCREEN

Q. How did you select comparable companies (peers) to estimate PGE's ROE?

A. I used companies that met the following criteria as peer utilities to the regulated utility activities of PGE:

1. Covered by VL as an U.S. Electric Utility;
2. Forecasted by VL to have Positive Dividend Growth;
3. S&P Local LT Issuer Credit Rating Between BB+ and BBB+;
4. No Decline in Annual Dividend in Last Five Years per SNL and VL;
5. Has 80 percent or greater Regulated Assets according to EEI;[20]
6. Has LT Debt between 45 and 55 percent of VL Capital Structure; and
7. No Large Recent M&A Activity relative to capitalization.

Q. Why do you eliminate companies that are not forecasted to have positive dividend growth?

A. My screening is consistent with Staff past practice. There is evidence that investors find common stock of dividend-cutting utilities less attractive. The stock prices for FPL Group's Florida Power and Light and for Niagara Mohawk Power Corporation declined sharply after dividend cuts.[21] These

[20] *See* Staff 502 Muldoon/2 for Edison Electric Institute breakout for regulated assets,

[21] An example of investor reaction to dividend cuts is found in The New York Times article, "Niagara Mohawk Stock Dives after Dividend Suspension", published January 25, 1996.

real-world findings are consistent with Staff's screening out utilities that have recently cut dividends.

Q. Did PGE apply a logical screen reflective of profession money managers and investment analysts?

A. Yes, PGE's screening methods generated a larger group than Staff would prefer when seeking a proxy group of utilities most like PGE. Staff prefers its screening because it selects a more targeted group of utilities most like PGE. One may presume that the more the peer screen component utilities resemble PGE, the more information the modeling results will be. Conversely the looser the screening criteria, the more generalized the modeling findings will be.

Q. What cohort of companies resulted from your screens?

A. Please see Exhibit Staff/502, Muldoon/2 for detailed Staff screens and also for a table that shows the list of peer utilities obtained from Staff screens and those obtained from PGE screens in this rate case.

SENSITIVITY ANALYSIS

Q. Did Staff also look at a sensitivity of Staff's Screen restricted to Mid-Cap companies with a capitalization similar in size to PGE?

A. Yes. Staff's modeling utilized: A) Staff's peers, B) Staff's Peers restricted to Mid-Cap companies as a sensitivity, and C) the Company's Peers.

Q. How does Staff apply informed judgment to its modeling?

A. Staff examined its full range of ROE results including sensitivities from 8.38 percent to 9.51 percent after all adjustments. Within that range, Staff determined that 9.0 percent to 9.3 percent is a reasonable narrowing of focus, focusing on Staff's peer companies. Further narrowing the focus to Staff's primary peers most like PGE Oregon operations was the best fit to capture investor expectations of PGE performance. Please note that the sensitivity restricting results to mid-sized utilities did not increase recommended ROE. It is important to note though that utilizing the Company's peer group in Staff's models generated the highest top-range of modeling results of 9.51 percent ROE.

Q. Does Staff's removal of the lower end of modeling, which are results from 8.03 percent to 8.75 percent, suggest Staff's results are fair, reasonable and conservative?

A. Yes, this is a representative indicator that Staff recommendations are balanced, fact-based and reasonable.

Q. Does running these sensitivities replace or modify Staff's primary screening methods?

A. No, Staff's results are consistent with past practice, practical and reasonable. Staff sensitivities analyses also confirmed that company size did not bias Staff's results. When Staff's peer group was restricted to only Mid-Cap companies with capitalization size like PGE's, Staff's ROE modeling results were lower, not higher.

GROWTH RATES

Q. What is the single most important element of discounted dividend or DCF models when used to estimate investors' required ROE?

A. The estimated rate of growth of future dividends is the most important element. I refer specifically to the singular growth rate for constant growth DCF models and the long-term growth rate for multistage DCF models such as those I use.

Q. What long-term growth rates did you use in the two DCF models?[22]

A. I used three different long-term growth rates, with different methods employed in developing each.

The first method uses a 50 percent weight applied to the average annual growth rate resulting from estimates of long-term GDP by the EIA, the OMB, and the CBO, with each receiving one-third of the 50 percent weight.[23] The remaining 50 percent is the average annual historical real GDP growth rate, established using regression analysis, for the period 1980 through 2016,[24] to which I apply the TIPS inflation forecast.

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22 Methods used here related to GDP-based growth rates are similar, if not identical to methods Staff has used in past proceedings. *See*, as an example, Staff's discussion of these methods and, to a limited extent, their conceptual underpinnings in Docket No. UE 233, at Exhibit Staff/800, Storm/46-52.

23 The EIA is the Energy Information Administration within the U.S. Department of Energy (DOE), OMB is the Office of Management and Budget, and CBO is the Congressional Budget Office. EIA and OMB's estimates are of nominal GDP. I applied to CBO's estimate of real GDP an inflation rate for the relevant timeframe developed using the Treasury Inflation-Protected Securities (TIPS) method described by Staff in testimony in multiple recent general rate case proceedings.

24 Staff discussed this approach in recent Staff cost of equity testimony in several rate case proceedings. *See*, as an example, in Docket No. UE 233 Exhibit Staff/800, Storm/46, line 15 through Storm/50 line 3.

The second long-term growth rate for Stage 3 dividends is a control reflecting a Blue Chip & OMB growth rate.

The Stage 3 annual growth rate, which I use primarily for illustrative purposes, is a nominal historical growth rate.

Please see Table 4 below for the growth rates I used in my modeling.

Table 4
GDP Growth Rates[25]

Stage 3 – Long-Term Annual Dividend and EPS Growth Rates					
Component	**Real Rate**	**TIPS Inflation Forecast**	**Nominal Rate**	**Weight**	**Weighted Rate**
EIA	**2.20%**	**2.04%**	**4.28%**	12.50%	0.54%
OMB - 10 Year GDP Projection			**4.10%**	12.50%	0.51%
White House Obama 2017 Budget			**4.30%**	12.50%	0.54%
CBO Projections			**4.00%**	12.50%	0.50%
Historical 1980 Q1 – 2016 Q3	**2.80%**	**2.04%**	**4.90%**	50.0%	2.45%
Composite				100%	**4.53%**
BEA Average Nominal Historical 1980-2016			**5.46%**	100.00%	**5.46%**
Indiana U – Kelley 2018-35 Ctr Econometric Research	**2.90%**	**2.04%**	**5.00%**	100.0%	**5.00%**
Blue Chip* – Top 10% 2019 Values	**2.90%**	**2.04%**	**5.00%**	100.0%	**Same**

Q. Does this approach capture a reasonable set of investor expectations similar to Staff's analysis in other recent general rate cases?

A. Yes, Staff modeling captures the expectations of investors who think variously that: A) future conditions will mirror the past, B) federal agency expert analysis also informs the historical track record, and C) the most optimistic 10 percent of Blue Chip referent persons surveyed have the pulse of the future. That last value represents the financial professionals who are most optimistic about the economy's long-run growth.

25 *See* Staff/503, Muldoon/1 for this material in electronic form.

Q. Is it appropriate to use estimates of long-term GDP growth rates to estimate future dividends for utilities?

A. Yes. In each of the Company's prior rate cases, Staff has shared plots of U.S. demand growth since 1950 on a three-year moving average. This downward trending consumption curve allows GDP growth to be a conservative proxy for both electric sales and dividend growth rates.

Q. Can relying on a long-term GDP growth rate overstate required ROE?

A. Yes. It is possible that my modeling overstates required ROE. My highest growth rate presumes return to high historical U.S. GDP growth rates. As Professor Aswath Damodaran of NYU Stern School of Business cautions in Chapter 13 of his book "Valuation", while the growth of the US economy will be a reliable upper bound for the growth of a company operating in that economy, there is no guarantee that the modeled firm will not fail or otherwise do worse than the overall economy. So two downward pointing risks in my ROE modeling are that A) the US GDP grows less robustly than shown and that B) PGE underperforms. This downward risk is real but not readily quantified.

Q. Is it important to distinguish between long-run 20- to 30-year rates and rates over the next five years?

A. Yes. Over-extrapolating a snapshot of short-term data undermines confidence in modeling results.

Q. Does Value Line (VL) share any concerns about PGE growth?

A. No. VL is optimistic about utility performance in general over the next five years. However VL suggests that the Company's stock is "priced expensively".[26] VL's caution is one reason for Staff's earlier discussion of equity issuance.

Q. What are the results of your multistage DCF models?

A. Please see Table 5 and Exhibit Staff/203 for a summary of modeling detail.

Table 5
Results of Staff's 3-Stage DCF Modeling
(See Exhibit Staff/203 for more detail)

Common Stock Flotation Costs Adjustment Shifts Range of Reasonable ROE's Upward by :				12.5	bps
Hamada Adjusted 3-Stage-DCF Model Results	8.38%	to	9.51%	ROE	
Staff Range of Reasonable ROEs	9.0%	to	9.3%	ROE	
Midpoint of Best Fit Modeling Results		9.2%	ROE		
(Staff's informed judgement excludes some of the lower range of modeling results depicted above)					
Staff Opening Testimony Point ROE Recommendation:		9.2%	ROE		

Q. How do these estimated ROE values compare with electric utilities' ROE values for 2016 General Rate Cases?

A. These estimated ROEs are low compared with average regulated U.S. utility authorized return on equity capital rate case decisions in 2016 of 9.6 percent. Some of that difference can be explained by incentives for the construction of certain types of generation and formula rates that have locked in some inputs from when required ROEs were higher a decade ago. Other higher ROE's such as for Avista's subsidiary Alaska Energy and Resources Company

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26 *See* the analysis by Paul Debbas, CFA of VL dated January 27, 2017 regarding POR, New York Stock Exchange (NYSE) ticker symbol for PGE.

(AERC) in Alaska or Hawaiian Electric reflect much more challenging and riskier isolated operations that cannot look to a well developed transmission grid as found in the Northwest or a power pool like the NW Power Pool for both routine and emergency assistance. [27]

Q. Did your analysis include the construction of a synthetic forward curve using UST TIPS break even points?

A. Yes. My forward curve is provided in Exhibit Staff/504, reflecting implied market-based inflationary expectations. Staff's recommendations are consistent with market activity indicating investor expectations of future inflation.

Q. Assume one ignored current downward adjustments by a broad spectrum of federal agencies and instead presumed that future U.S. GDP growth would look like the past 30 years. Would a ROE based on that assumption fall within Staff's recommended range?

A. Yes, I extracted and ran regression on data from U.S. BEA to generate the annual real historical GDP growth rate shown in Table 4 above. My recommended range of ROEs includes values that presume GDP growth over the next 30 years would look like that of the past 30 years.

Q. Do you show this analysis in your exhibits?

A. Yes. Exhibit Staff/505 shows my analysis in support of this finding.

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[27] *See* Dennis Sperduto, "ROE Authorizations in 2016, Slightly Below Those in 2015" Regulator Research Associates (RRA) an affiliate of SNL Financial LC and S&P Global Market Intelligence, published January 19, 2017.

Q. If utilities' dividends and EPS are growing at a faster rate than growth for the whole economy, then utilities would become a bigger part of the economy. Is that happening?

A. No. Utilities are not becoming a larger and larger part of the U.S. economy.[28]

Q. How do your methods employed in this case differ from those utilized by Staff in PGE's recent general rate cases, and in the last Northwest Natural Gas Company rate case, Docket UG 221?

A. My methods and modeling parallel those employed by Staff in recent general rate cases.

ALTERNATIVE MODELS EXAMINED

Q. What control modeling did you perform to corroborate your DCF results?

A. I performed CAPM calculations that support my DCF modeling. While I do not recommend that any alternate approach should replace the Commission's reliance on three-stage DCF modeling, such alternate models may offer a check on the reasonableness of my recommendation.

Q. Please discuss the Ibbotson approach you used.

A. The Research Foundation of CFA Institute, an impartial non-profit organization, published "Rethinking the Equity Risk Premium" in 2011. Here, Professor Roger Ibbotson of the Yale School of Management, and other

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[28] *See* UE 283 Staff/200, Muldoon/17-22.

earlier examiners of how best to approach and calculate equity risk premiums, share their current thinking and findings.

"In the 85 years covered by the Ibbotson data, stocks delivered a real return of 6.6% against 2.1% for bonds, supporting a 4.5% equity risk premium."[29] Adding that 4.5 percent to about a potential 4.00 percent UST risk free rate for end of 2016, would suggest that an investor looking just for a quick rough estimate should demand about an 8.5 percent ROE to be satisfied to own a stock of average risk at year end 2016.

Q. Did you consider other market risk premiums in your CAPM modeling?

A: Yes, where the Ibbotson most focuses on my adult lifetime, 1980 to present, Morningstar in "Stocks, Bonds, Bills and Inflation 2015 Classic Yearbook provides a market risk premium of 6.0 percent based on 1926 through 2014. I also run my CAPM modeling using this alternative 6.0 market risk premium.

Q. Did you examine both 10- and 30- year UST yields as your market risk-free rates, and did you use the higher market forwards to pertinent bond issuance timeframes in the test year in this rate case?[30]

A: Yes, I also looked at both VL and Yahoo Finance betas, and both the Company's peers followed by VL as electric utilities and Staff's preferred peer

[29] "Rethinking the Equity Risk Premium," Research Foundation of CFA Institute, p 81 (2011).

[30] Note that the Company ignores the usual market practice of using 10-Year UST yields as a risk-free rate in CAPM modeling. Moody's Investment Services for example lists both the 10- and the 30-year UST yields under risk free rate.

group. For these reasons, the Commission can conclude that this modeling was reasonably examined using inputs commonly employed by investors looking for a fast rough general direction of returns.

Q. How do your CAPM results inform consideration of your more robust three-stage DCF models?

A. My CAPM modeling can be interpreted as a downward pointing vector in my range of reasonable ROEs. However, it is interesting to see that the top point ROE recommendation from my CAPM modeling is generated by Staff's Peer Group restricted to mid-sized companies. My CAPM modeling results are lower than results from my three-stage DCF analysis. Put another way, my CAPM modeling results do not imply that my DCF results should be higher. But the CAPM work flags the need to watch Company size to make sure it does not generate downward bias. I address this concern with Mid-Cap sensitivities in my three-stage DCF analysis.

<u>REBUTTAL OF PGE'S MULTI-STAGE DCF MODELING ADJUSTMENT</u>

Q. Did PGE's witness conduct multi-stage DCF modeling?

A. Yes. The PGE witness's multi-stage DCF modeling obtained results very similar to my own. Using the multi-stage DCF model, Dr. Villadsen estimated a 9.1% ROE using a combination of the Office of Management Budget (OMB) and Blue Chip GDP long-term growth rate (and 9.0% using the Blue Chip alone).[31] However, Dr. Villadsen asserts that PGE's smaller market

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[31] PGE/1100, Villadsen/1-2.

capitalization warrants a size premium of 60-70 basis points, and concludes that the adjusted multi-stage DCF modeling results are 9.6 – 9.8 percent.

Q. Does your mid-size sensitivity modeling refute Dr. Villadsen's assertion that PGE's smaller capitalization warrants the addition of a size premium of 60 to 70 bps to the results of the multi-stage DCF model?[32]

A. Yes. Based on my mid-cap sensitivity there is no need for an outboard adjustment to the multi-stage DCF modeling results to account for PGE being a small to medium sized company.

First, Staff's modeling tested whether Staff's recommended ROE would be higher if only companies about the same size as PGE were modeled. The results of this sensitivity analysis showed in that the required ROE would need to be 30 basis points LOWER were only companies the size of PGE modeled.[33]

Second, PGE has actually grown substantially over the last decade and is a medium sized or mid-cap company now. While PGE was once about the same capitalization size as NW Natural, it has since grown both its capitalization and rate base to become about twice as big as NW Natural. PGE's characteristics are no longer those of the smallest publicly traded investor owned utilities.

Third, Staff's screening seeks to find the half dozen or so peer companies that can best act as a proxy for PGE. By using six companies that

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32 PGE/1100, Villadsen/1-2.
33 Staff/503, Muldoon/1.

can closely stand in for PGE in terms of a variety of financial characteristics, Staff does not have to make so many outboard adjustments that can come from using 25 of 47 companies or half the companies followed as electric utilities by Value Line. Outboard adjustments can be seen as another way of saying that screening may not be tight enough to have selected companies similar enough to PGE to create a reliable proxy group.

Dr. Villadsen uses this 60 bps bump selectively and not on the results of her single-stage DCF analysis. If she did, the upper range of her single-stage DCF would be 10.9 and the mid-point of her multi-stage and single-stage DCF modeling would be about 10.3, which is clearly too high. As noted above, Staff's modeling would not have generated a higher recommended ROE were Staff's screening restricted to companies about PGE's size. This sensitivity analysis undermines Dr. Villadsen's assertion that a 60 bp bump is required, as done her arbitrary application of the bump.

Q. Dr. Villadsen also asserts that if her multi-stage results are included in the range of results of ROEs, the multi-stage DCF results should have a 20 basis point bump to account for the P/E ratio being overstated and the dividend yield being understated.[34] Do you agree?

A. No. I think that this concern can be addressed with somewhat tighter peer screening, wherein less adjustment to the modeling is necessary because one starts with Companies somewhat closer to PGE.

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[34] PGE/100, Villadsen/35-36.

REBUTTAL OF SINGLE-STAGE GORDON GROWTH DCF MODELING

Q. Did you examine the Company's constant Gordon growth DCF model, also called the Dividend Discount Model (DDM)?

A. Yes. However, I note that Brealey, Myers and Allen, in the tenth edition of their textbook "Principles of Corporate Finance" caution that "the simple constant-growth DCF formula is an extremely useful rule of thumb, but no more than that."[35]

Q. Do you view this model as simply an extremely imprecise vector and largely a training tool for new finance students?

A. Yes. Single-Stage DCF is not a method that one would want to weigh heavily were one responsible for investment decisions and results. This model exposes students to financial modeling at an approachable level of complexity where no actual funds are risked on the erratic modeling results. Staff would not average the Company's 10.3 single-stage result with other modeling as it is expected to be wrong. The Commission rejected results of the single-stage in several rate cases since 1999.[36]

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[35] "Principles of Corporate Finance", Brealey, Myers, and Allen, p 83 (10th Edition 2010).

[36] Order No. 01-116 (Docket No. UE 116) ("[W]e reject use of a single-stage DCF analysis in this docket."); Order No. 01-115 (Docket No. UE 115) (Same); (Order No. 12-437 (Docket No. UG 221) ("[W]e give no weight to the results of NW Natural's single-stage DCF analysis"); See also Order No. 99-697 (Docket No. UG 132) ("We also reject Mr. Rothschild's simple DCF results in favor of his complex DCF analysis. We agree with Staff and NW Natural that a multi-stage DCF improves on the implicit assumption in the single-stage DCF that dividends grow indefinitely at the same rate.") But See Order No. 07-015 (Docket No. UE180/181/184 (Not addressing ICNU's reliance on single-stage DCF model as sensitivity analysis).

Q. Why is it reasonable to not equally weight the very simplest model for valuing equity as the present value of expected dividends on it?

A. This simple Gordon Growth model presumes that all peer utilities will succeed and sustain their current rate of dividend growth forever. As one might presume, extrapolating this year's condition forever would ignore additional information that is projected at this time. This steady state model, to quote Professor Damodaran of the NYU Stern School of Business, from Chapter 13 of his book "Valuations", can yield misleading or even absurd results".

Q. Can the Gordon Growth single-stage DCF model be calibrated to be informed by CBO 20 year projections of growth rates or the U.S. Social Security long-run population projections?

A. No. The single-stage model has only two inputs: 1) What is the next dividend; and 2) the single rate of growth at which the earnings and payouts of the utility and all of its peers will grow in perpetuity.

Q. What if the economy is doing a little better now in terms of GDP growth than the CBO project it will do 20 years out?

A. In that scenario, which is consistent with thinking of the investment community, the single-stage DCF model will overstate required ROE because it is not informed by and never corrects for longer-run lower data even though those projections are available now. This simple Gordon Growth model isn't a rocket ship with telemetry and navigational computer. Rather you point it up and light it off. Any other information you have cannot be incorporated into this model.

Q. What are the positives of the simple Gordon Growth Model?

A. It is simple, requiring less assumptions.

Q. What if the peer utilities have opportunities to build new generating plants and transmission lines and do not pay out all free-cash flow to equity (FCFE) as dividends, but rather build some plants like Carty.

A. Then the Single-Stage DCF model will be wrong and overstate required ROE.

Q. What if some of the peer utilities are growing dividends fairly quickly now, but can only sustain this with internal cash flows for about five years before returning to a lower dividend payout ratio.

A. Then the simple model will be wrong and overstate required ROE.

Q. Why does a single-stage DCF model result in a higher ROE?

A. The simpler model has extremely limited inputs and ability to accept nuanced information. For example, investors know that the CBO expects long-run GDP growth over a 20-year time frame to be lower than in the next couple of years. This reflects challenges in US working population and productivity discussed earlier. The simple model just presumes that current growth will continue forever.

The model is not informed by additional steps down in GPD growth. The construct can't handle additional inputs. And in contrast to the three-stage DCF, which incorporates the more complex inputs, the single-stage DCF generates a known wrong answer. That is good enough for personal finance perhaps, which could account for 1.1 percent of the holders of PGE stock. It isn't good enough for a financial manager with fiduciary responsibilities, which according to Yahoo finance hold 98.9 percent of PGE stock.[37]

REBUTTAL OF PGE'S RISK PREMIUM MODELING

Q. Please describe the Risk Premium modeling relied on by Dr. Villadsen.

A. Dr. Villadsen's Risk Premium modeling looks at the relationship between authorized ROEs and bond rates from 1990 to 2016. But before we go further with this model, we likely need to ask an important question. Do we expect that relationship to be predictive of a relationship between the same variables in PGE's test year and if so why.

Q. Did you examine PGE's Risk Premium modeling methods?[38]

A. Yes. However it is exceedingly uncertain whether investors with the 2008 economic downturn and strong U.S. Federal Reserve market interventions fresh in mind would presume that risk premium modeling will correctly predict forward looking markedly divergence Federal Reserve policy.

Q. Was there any significant event in this time block that might distort results?

A. Yes, in the economic downturn of 2008-2009, markets were disrupted, and correlations did not hold true to past trends.

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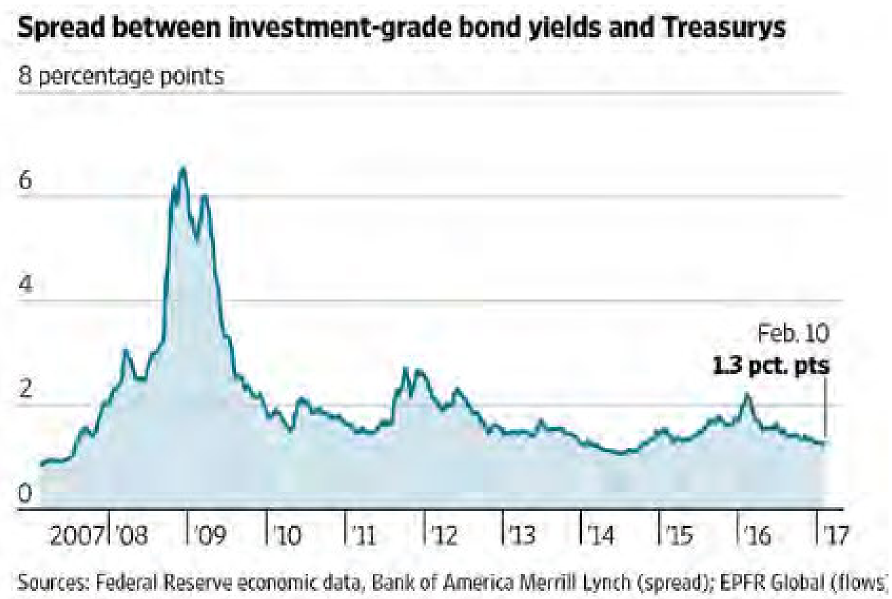
37 Staff notes that as of June 7, 2017, Yahoo Finance shows that 98.9 percent of PGE's shares are held by institutional investors and mutual funds. https://finance.yahoo.com/quote/POR/holders?p=POR

38 PGE/1100, Villadsen/37-38.

Figure 4[39]



Q. Are there other good reasons to believe that an examination of historical fixed-income data and an extrapolation of relationships between these variables is not predictive of the future?

A. Yes, April 2015 Federal Reserve Policy Committee minutes released May 20, 2015, re-defined the Fed's "equilibrium rate" as the level of the FED funds rate, adjusted for inflation, consistent with the economy achieving, over a specified time horizon, maximum employment and price stability.[40]

Federal Reserve Chairwoman Janet Yellen, in testimony on Capitol Hill, February 14, 2017, said she remains reluctant to base current monetary

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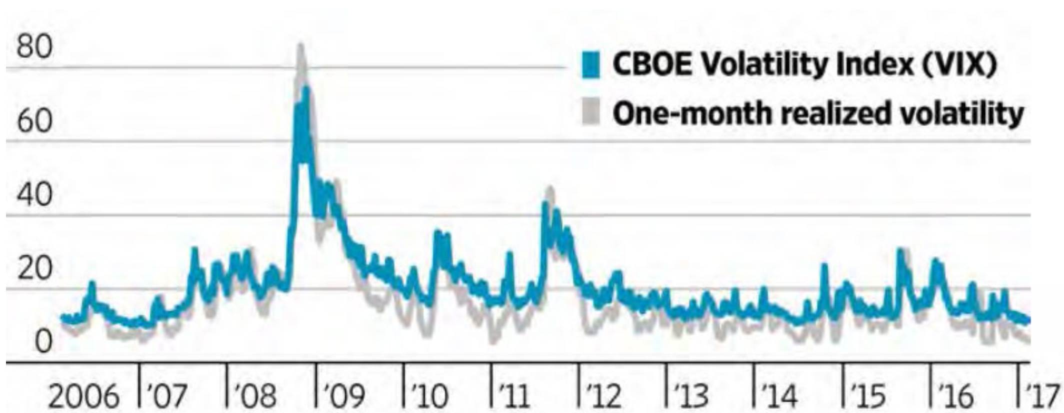
39 See Chris Dietrich, "Bond Buying Soars, Yields Tighten", WSJ, February 13, 2017.

40 Staff accessed the WSJ article, "A New, Lower Normal for FED Rates? FED Officials' Lively Debate" by Pedro Nicolaci da Costa on May 22, 2015, at www.WSJ.com.

policy on speculation around the possibility of tax, regulatory, infrastructure and health-care policies that are intended to boost the growth rate.[41]

As an easy mental exercise, imagine results of risk premium projections of investor-required ROE with and without years 2008 and 2009, which clearly distort both spreads between U.S. investment grade corporate bond and UST yields shown above in Figure 4 and the Chicago Board Options Exchange's Volatility Index (VIX) shown below in Figure 5. Investors may be hesitant to base forward looking expectations on assumptions markedly divergent from conditions in the last five years, without strong referent expert consensus projecting another imminent great recession or depression. As 2008 and 2009 conditions are rare or "black swan" events, there may be greater reliance on federal government referent sources for forward-looking long-run projections than long-historical extrapolations that are not informed by Federal macroeconomic policy changes since 2009.

Figure 5[42]



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[41] See "Fed's Yellen Plays Down Speculation about Trump Boom", WSJ, February 14, 2017.

[42] See James Mackintosh, "What VIX Is Really Telling Markets", WSJ, February 14, 2017.

Visually note the spikes in Figures 4 and 5 near years 2008 and 2009. It may be that investor's expectations of returns may be more informed by 2012 through 2016 trends.

REBUTTAL OF PGE'S CAPM AND ECAPM MODELING

Q. Did you examine PGE's CAPM and ECAPM model?

A. Yes. Differences between Staff's and PGE's CAPM results can be largely explained by the differences in inputs for the risk-free interest rate and market equity risk premium.

CAPM Input Differences	PGE[43]	Staff[44]
Risk Free Rate	3.34% to 3.89%	**3.68% to 4.30%**
Market Risk Premium	6.54%	**6.0%**

Q. What are these input differences?

A. Staff uses a lower risk-free rate and also a lower market risk premium. Typically one would use the 10- or 30-year U.S. Treasury (UST) yield to represent the risk free rate. Please see Staff/507, Muldoon/5 for Bloomberg's forward rates for UST. Staff attributes this difference in part to timing. There was a surge in projected UST yields shortly after the US presidential election which has since subsided.

43 PGE/1103, Villadsen/4.

44 Staff/506, Muldoon/1.

In the case of risk premiums, Staff relies more heavily on Professor Ibbotsen's recent writing on capital markets, than interpretations of his work by others that contradict the expert. A theme of Professor Ibbotsen's is that people can overestimate market premiums.

Q. What is Empirical or ECAPM?

A. Dr. Roger Morin, PhD in his book, "New Regulatory Finance" notes how CAPM seems to be off in its projections of required rates of return. Dr. Morin offers a correction which by pivoting model results, might offer a remedy to investors consistently disappointed by CAPM modeling results. I suggest that this approach is interesting, but has not caught on and merits little weight here.

The Company's Scenario 1 uses a 3.9 percent risk free rate when Bloomberg projects a 30-year UST yield closer to 3.0 percent in mid-test year. However, were the Commission to accept results in the 9.5 to 9.6 percent ROE range, ECAPM pushed up results roughly as one pivots or puts their finger on the scale. This continues to make ECAPM results suspect.

LOOKING FORWARD

Q. You seem to be leveling usual criticisms that certain models have high inputs and certain other models merited no weight in Oregon.

A. Yes, some models that generate clearly wrong but high values seem to be slow to die. New approaches might be tracked over time and become integrated into Oregon best practice. Repetition of Commission rejected models that have merited little or no weight in Oregon general rate cases may be delaying the Company's development of new approaches that could better inform the Commission over time.

Q. Is there greater overlap of Staff modeling results to the Company's in this rate case?

A. Yes, and that is encouraging. In the above results the high end of the range was best represented by Hamada adjusted results that reflect a 12.5 bps equity flotation costs inclusive of equity forward costs. The highest values were generated by PGE's peer group. As Staff reflects, it finds Staff's peer group and associated results most reflective of PGE's experience.

HAMADA EQUATION

Q. Your application of the Hamada Equation to un-lever peer utility capital structures and to re-lever at PGE's target capital structure increases required ROE. Why is this adjustment reasonable?

A. I employ the Hamada Equation as a check on the reasonableness of my modeling results. As earlier discussed, my screening criteria already identify peers that have a very close capital structure to PGE's. Use of the Hamada adjusted results helps ensure that I have captured all material risk in my analysis.

INFORMED STAFF ANALYSIS

Q. Did you take into account information from other models?

A. Yes. I performed CAPM modeling and reviewed the Company's testimony, which informed my recommendations.

Q. Do you monitor and analyze current and projected market conditions?

A. Yes. My analysis includes analysis of the current economic climate and its impact on my estimates of long-term growth. I also rely heavily on feeds from SNL Financial LC (SNL), Bloomberg, Moody's, S&P, WSJ and other sources to make sure that my financial understandings are reflective of investor expectations. Please see a cross section of recent news in Exhibit Staff/510.

Q. Did you develop your recommendations while informed by authorized ROEs in other parts of the country?

A. Yes. I examined 2016 authorized ROEs across the nation captured in ROE decisions published by SNL Financial LC, as discussed earlier.

Q. Did you use robust and proven analytical methodologies?

A. Yes. My methods are robust, proven, and parallel Staff's work over the last decade.

Q. Please summarize your analysis.

A. Using the cohort of proxy companies that met my screens, I ran each of its two DCF models three times, each time using a different long-term growth rate.

Q. How did you evaluate the Company's peer cohort and other tests?

A. After performing these initial runs, I performed sensitivity analysis.

Q. Is the upper end of your range of reasonable ROEs driven by results from the Company's peer group utilizing the top growth rate?

A. Yes, the upper range of reasonable ROEs is from PGE's peer group utilizing the highest growth rate adjusted for capital structure divergent from PGE's.

Q. What is the highest end of range for all Staff modeling inclusive of all modeling and sensitivities Staff looked at?

A. The highest end of range with Company peers in Staff's modeling was 9.51 percent ROE.

Q. Informed by that result does Staff still recommend a range of reasonable ROEs of 9.0 percent to 9.3 percent with a point ROE of 9.2 percent?

A. Yes, that is correct.

ISSUE 3 – COST OF LT DEBT

Q. Have you compiled a summary table illustrating your calculation of PGE's Cost of LT Debt?

A. Yes, please see Confidential Exhibit Staff/507 supporting my recommendation for a 4.852 percent Cost of LT Debt.

Q. Is this table updated to reflect PGE's test year planned debt issuance(s) and pro forma replacement of the current portion of LT Debt maturing in the test period?

A. Yes. This table remains confidential until the Company informs the public of issuance detail.

Q. Did you utilize Bloomberg forwards for market yields on UST as of likely issuance dates through the test year? And did you also plot trending spreads over UST for like rated U.S. utilities?

A. Yes. Staff's methods herein are consistent with its methods in other recent PGE general rate cases.[45]

Q. Did you prepare a debt maturity profile for PGE?

A. Yes, in Exhibit Staff/507 I provide both a current snapshot SNL Financial LC (SNL) debt maturity profile and a separate debt maturity profile for the test period reflecting Staff's proposed Cost of LT Debt table. These profiles show that Staff's recommendations avoid maturity concentrations.

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45 Staff's approach to Cost of LT Debt is consistent with Staff's work in recent PGE general rate cases, namely: Docket No. UG 246 (Order No. 14-015), Docket No. UG 284 (Order No. 15-109), and Docket No. UG 288 (Order Nos.16-076 and 16-109).

Q. Did you examine possible cost savings from the issuance of "Green Bonds" where tranches of PGE borrowing designated for environmentally friendly utility purpose could bear a designation informing investors demanding this type of financial investments an opportunity to know that certain bond series were so targeted?

A. Yes, PGE addressed this question in its confidential responses to Staff DR Nos. 586 to 593. At this time, conditions have not converged to allow PGE to test public market demand for tranches of bonds supportive of "Green" purposes. PGE continues to monitor markets for conditions in which Green Bonds would provide a net benefit, after accounting for certification and tracking, above the costs and flexibilities of alternative issuance options.

Q. Are there uncertainties regarding amount, time of issuance and maturities of bond issuances in 2017 and 2018?

A. Yes, it is possible that PGE's maturing debt and emerging capital spending needs could result in changes to PGE's planned issuances as described in PGE's Exhibit 1001 and in PGE's presentation to investors in March 2017 provided in Exhibit Staff/511.

Q. Has the Commission approved a way that if adopted, would provide PGE with greater flexibility regarding the amount, maturity and timing of new bond issues?

A. Yes, PGE and parties stipulated in PGE's last general rate (Docket No. UE 294) case to a benchmark LT Debt table derived from Staff's exhibits.[46] This

[46] See Order No. 16-098 (Docket No. UM 1756).

allowed for the capture of actual issuance detail through the end of that case's test year, with $1.58 million annual amount approved for deferral by Commission Order No. 16-098. This difference between actual and projected costs are deferred and retired to ratepayer benefit. The 2016 amount is being amortized during 2017 through Schedule 105. The 2017 deferred amount will be amortized through Schedule 105 in 2018.

Q. Can this work smoothly in this rate case?

A. Yes. In Docket No. UE 294, a planned bond issue changed in terms of amount, maturity and timing. This above approach allows for rates to reflect actual costs for debts thereby providing all parties more assurance that rates are just and reasonable without unduly constraining the Company's ability to best manage needed issuances.

Q. Is this last idea describing any discussions or settlement activity?

A. No. This is merely an approach that has worked in prior circumstances to the satisfaction of all parties.

Q. What is your recommendation absent above the alternative approach?

A. My 4.852 percent Cost of LT Debt is consistent both with the Company's responses to DRs and Company policy, and with Staff best practices in recent rate cases.

ISSUES 4 — POST-RETIREMENT EXPENSES

Q. Please describe pension expense?

A. Since 1987, employers are required to use Financial Accounting Standard (FAS) 87 for financial reporting of pension costs.[47] FAS 87 requires employers to recognize the cost of their pension plans on an accrual rather than a cash basis.[48] In other words, pension cost is recognized over the period during which benefits are earned, or "accrued" — that is, during the working years of the employees that will receive the pension benefits during retirement.[49]

Because FAS 87 expense is based on an accrual, not cash basis, the amount of pension costs recorded is generally different than the actual amount of annual contributions made.[50] Over the life of the plan, however, total contributions are expected to equal total FAS 87 expense (as well as FAS 88 expense related to pension plan termination).[51]

The FAS 87 expense, which can be positive or negative, is calculated based on four components:

- Service cost - The value of the benefits earned, or accrued during the current year based on the applicable benefit formula for each participant.
- Interest cost - The interest on the pension plan liability (projected benefit obligation) for the year. This amount increases pension cost.

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47 Order No. 15-226 at 2.

48 Id.

49 Id.

50 Id.

51 Id.

- Expected return on assets - The expected return on assets for the year, which if positive will reduce pension cost. The difference between the actual return on assets and the expected return on assets represents an actuarial gain or loss that will be recognized in future pension cost.

- Amortizations of unrecognized costs - The change in liability due to plan changes, changes in actuarial assumptions used to value plan liabilities, differences between past differences between expected and actual asset returns, and other unrecognized gains and losses.[52]

When the pension fund trust is producing significant investment gains, the FAS 87 expense can be negative, signaling that the trust is in good financial health. When the pension fund investments lose value, the FAS 87 turns positive, signaling a need for increased contributions.

Q. Has the Company provided confidential updates in the last 30 days on each of the above four components in responses to Staff DR's 178 through 200?

A. Yes, the Company provided these confidential updates. Staff also went through the Company's SEC Form 10K filings.

Q. What are Staff's conclusions regarding pension expense?

A. The Commission relies on FAS 87 expense as a reasonable representation of cash costs in any given year. The FAS 87 expense amount is calculated and determined by third-party actuaries. Two inputs require a degree of subjective judgment; these are the Expected Return on Assets (EROA) and the expected discount rate. PGE testimony showed that its EROA is 7.0 percent, which is reasonable at this time with regard to pensions and post-

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52 Id.

retirement expenses.[53] Staff also found the expected discount rate is reasonable as estimated at this time.

Q. Have you an adjustment for Pensions and Post-Retirement Expense?

A. Staff does not have an adjustment now based on the Company's responses to DR Nos. 178 through 200 that have been received by Staff through May 15, 2017. Based on Commission Order No. 15-226 in Docket No. 1633, PGE excluded prepaid pension asset and associated deferred tax liability from PGE's rate base. So far this generally describes a continuity approach to Pensions on the part of PGE.

Q. Does Staff propose any adjustment at this time based on discount rates for pensions and post retirement expenses?

A. No. Staff notes that discount rate assumptions are still subject to update by the Company's actuaries and cannot be seen as finalized yet. Updates and changes as late as September could occur. However, Staff will not have adequate opportunity for discovery or to present testimony on any update. To the extent updated information is provided by PGE's actuaries after Staff's opportunity to investigate has passed, the information should not be given much weight.

[53] *See* PGE/400, Mersereau-Jaramillo/31.

Q. Does Staff recommend an adjustment based on the Company's updated CONFIDENTIAL ATTACHMENTS to Staff DR Nos. 178 and 194 showing pension and post retirement expense trends?

A. No. However, Staff would like to amplify an issue PGE has raised regarding accounting practices that could potential increase costs, absent any Commission action in the first quarter of 2018.

Q. Will FASB accounting standards for pensions change for calendar year public companies on January 1, 2018?

A. Changes are being discussed under an Accounting Standard Update (ASU). The ASU has potentially two effects. The first is to create a single designation of Accounting Standards Codification (ASC) 715 which would now address pension expenses formerly found under FAS 87 as well as certain other post retirement expenses such as post-retirement medical expenses formerly found under FAS 86). This action might be seen as similar to putting several files in the same filing cabinet without changing the content of the files.[54]

The other series of changes is more complex and current drafts could vary from final language. The accounting firms describe the current guidance as still very fluid. The recommended accounting practice for 2018 could ask that net periodic pension costs be disaggregated into its component costs. Amounts eligible for capitalization could be limited to service cost

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[54] Financial Accounting Standards Board (FASB), Accounting Standards Codification (ASC), Topic 715 collapses down in everyday reference to ASC 715. This is the topic under which FAS 87 and FAS 106 now jointly reside

components. PGE Exhibits 400 and 900 in conjunction with ongoing response to Staff DRs 178 to 200 address this topic.

Q. Do all jurisdictional energy utilities see the same common logical path forward with certain actions needed by times certain?

A. No. Perhaps because FERC appears willing to consider divergent well developed approaches, no federal agency such as the ICC or SEC requires any particular compliance action at this time, and actual guidance could change near or in 2018 Q1, opinions vary as to best approaches.

Q. Are there any certainties that jurisdictional utilities can count on now?

A. Not yet. It looks like utilities, despite seeing greater effects under proposed language than other types of companies, will not be exempt. Conversely, it looks like any accounting order from the Commission would override guidance regarding best accounting practices and be acceptable to FERC as a common framework for how Commission jurisdictional energy utilities should best be informed by the pensions ASU within the context of doing no harm to ratepayers.

Q. What is the purpose of the guidance in this ASU?

A. The goal is to provide investors with greater transparency than was provided to date by aggregated line items in financial statements and reporting.

Q. A basic rule of corporate finance is to take no real action causing financial harm to one's firm based on general accounting guidance. Essentially this translates to, "Avoid losing real money because of how the Company choses to record and account for operations." How would that managerial rule apply in this case?

A. That concept still applies here. A company finance team in meeting its fiduciary responsibility to the firm generally does not accept real losses to accommodate general accounting guidance.

Q. Could a Commission order be helpful prior to when utilities account for the first quarter of 2018 and prepare quarterly filings for the SEC in 2018 Q2?

A. Yes. However utilities may still follow Commission Order No. 15-226 regarding pension cost recovery now, and can presume cost and cash flow treatments as usual now for rate case purposes.

Q. How does Staff recommend the Commission frame this issue should it chose to review PGE's draft accounting treatment language provided in PGE/400 Mersereau – Jaramillo/30 at lines 12 to 26?

A. Staff recommends that the Commission start with a target end result of: 1) no harm to ratepayers through accepting this accounting guidance; 2) no real costs to jurisdictional utilities through accepting this accounting guidance; 3) no increased unnecessary complexities; 4) common treatment to the extent possible across jurisdictional energy utilities for both pension and other post-retirement expenses; and 5) retention of Commission guidance in

Commission Order No. 15-226 to the extent possible, which fosters a long-term view toward pension management in lieu of single year conclusions about the health of supporting investments.

Q. Does Staff's testimony or lack of adjustment commit the Commission to issuing an accounting order by any date certain?

A. No. Should the Commission decide to look at this issue in another forum or to take longer than the rate case timeframe to consider how best to craft an accounting order, that delay would create no real harm to PGE or its ratepayers. The primary value of PGE's testimony on this subject is bringing Commission awareness to this upcoming but not yet imminent set of changes to accounting guidance.

Q. You say you are still working on this issue. What are you looking at?

A. Staff continues to evaluate updated information as it is available and to work with its attorneys to understand from a variety of perspectives what is required to continue the overall guidance of Order No. 15-226, minimizing negative ASU impacts to ratepayers and Company.

ISSUES 5 — AFUDC

Q. In your examination of the Allowance for Funds Used During Construction (AFUDC) did Staff's investigation and analysis result in an adjustment?

A. Not at this time. I appreciate the Company's cooperation in responding to numerous multi-part DRs, which I continue to review in conjunction with Staff's last audit review of AFUDC.

Q. Are there next steps in this or adjacent areas in this rate case?

A. Yes. My three primary focus areas are:

1. Adherence to process including FERC exceptions;
2. Changes in cost per unit of capital spending over time for PGE; and
3. Cost per unit of capital spending across jurisdictional energy utilities, addressing funding securities mix and maturities.

Q. Are you working on this topic in support of any other Staff testimony?

A. Yes, I am working in support of Lance Kaufman, who is looking at Carty costs and appropriate rate treatment and calculation of AFUDC.

CONCLUSION

Cost of Capital

Q. What is Staff's recommendation regarding Capital Structure?

A. I recommend a 49.5 percent Common Equity and 50.5 percent LT Debt Capital Structure, reflecting best available information at this time.

Q. What is Staff's recommendation regarding ROE?

A. I recommend that the Commission consider a range of reasonable ROEs from 9.0 percent to 9.3 percent, and a point ROE of 9.2 percent — the midpoint in my range of most reasonable ROEs.

I note that PGE has presented more comprehensive and better structured CoC testimony than recently seen by the Commission in prior rate cases. For example, the Company's multi-stage DCF peer screening is logically consistent and not incompatible with Commission preferred methodologies. As I performed additional sensitivity analysis, higher modeling results were obtained when using the Company's peer utilities run through the Commission's preferred modeling as described in the body of this testimony.

Other sensitivity analysis addressed PGE's capitalization size concern precluding a need for adjustments beyond Staff's routine Hamada treatment and recognition of equity flotation costs.

Q. What is Staff's recommendation regarding LT Debt?

A. I recommend a Cost of LT Debt of 4.852 percent which reflects the replacement of higher cost maturing bonds with lower cost issues. My mix of maturities is consistent with Company policy and historical practice.

Q. Do you have a recommendation to increase Company flexibility while capturing possible savings in Cost of LT Debt for ratepayers?

A. Yes, an alternative to reliance on my projections is to capture actual detail of LT Debt issuances through the test year; to defer the difference between actual and projected costs; and to retire any savings to ratepayer benefit.

Q. What ROR is generated by the above recommendations?

A. Staff's recommendations generate a 7.004 percent ROR.

Pension/Post-Retirement Expense

Q. Does Staff have an adjustment to Pensions and Post-Retirement expense at this time?

A. No. Staff continues to monitor changes and updated information, and makes a recommendation to the Commission.

Q. What position does Staff recommend the Commission take on Retirement Expense?

A. I recommend that the Commission take a cautious business-as-usual approach to accounting changes regarding pensions.[55] The Commission has provided valuable guidance to date on appropriate pensions and post retirement expense methods. As the Commission looks at this subject further, an accounting order clarifying the Commission's preferred accounting can offer guidance to jurisdictional utilities and provide a regulatory umbrella over processes that prevent real losses for both ratepayers and utilities.

[55] Order No. 16-076, p. 6 at part F.

AFUDC

Q. Does Staff have an adjustment to AFDUC at this time?

A. No. However, Staff continues to examine this issue.

Q. Does that conclude your testimony?

A. Yes.

CASE: UE 319
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Witness Qualification Statement

June 16, 2017

WITNESS QUALIFICATION STATEMENT

NAME: Matthew (Matt) J. Muldoon

EMPLOYER: PUBLIC UTIILTY COMMISSION OF OREGON

TITLE: Senior Economist
Energy – Rates Finance and Audit Division

ADDRESS: 201 High Street SE, Suite 100
Salem, OR 97301

EDUCATION: In 1981, I received a Bachelor of Arts Degree in Political Science from the University of Chicago. In 2007, I received a Masters of Business Administration from Portland State University with a certificate in Finance.

EXPERIENCE: From April of 2008 to the present, I have been employed by the OPUC. My current responsibilities include financial and rate analysis with an emphasis on Cost of Capital. I have worked on Cost of Capital in the following general rate case dockets: AVA UG 186; UG 201, UG 246, UG 284, UG 288, and UG 325 current; NWN UG 221; PAC UE 246, and UE 263; PGE UE 262, UE 283, and UE 294; and CNG UG 287 and UG 305.

From 2002 to 2008 I was Executive Director of the Acceleration Transportation Rate Bureau, Inc. where I developed new rate structures for surface transportation and created metrics to insure program success within regulated processes.

I was the Vice President of Operations for Willamette Traffic Bureau, Inc. from 1993 to 2002. There I managed tariff rate compilation and analysis. I also developed new information systems and did sensitivity analysis for rate modeling.

OTHER: I have prepared, and defended formal testimony in contested hearings before the OPUC, ICC, STB, WUTC and ODOT. I have also prepared OPUC Staff testimony in BPA rate cases.

Abbreviations: AVA – Avista Corp., CNG – Cascade Natural Gas Company, IPC – Idaho Power Company, NWN – Northwest Natural Gas Company, PAC – PacifiCorp, PGE – Portland General Electric Company

CASE: UE 319
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 502

Staff Peer Screening

Exhibits in Support
of Opening Testimony

June 16, 2017

Acronyms and Abbreviations Used

CIK	SEC Central Index Key
EDGAR	SEC Electronic Data Gathering, Analysis and Retrieval System
EEI	Edison Electric Institute
EIN	IRS Employer Identification Number
IRS	U.S. Internal Revenue Service
SEC	U.S. Securities and Exchange Commission
SIC	Standard Industrial Code
SNL	SNL Financial, LC – A financial Information gathering firm
U.S.	United States of America
VL	Value Line Investment Survey, The

Moody's		S&P		Fitch		DBRS		
Long-term	Short-term	Long-term	Short-term	Long-term	Short-term	Long-term	Short-term	
Aaa	P-1	AAA	A-1+	AAA	F1+	AAA	R-1H	High Grade
Aa1		AA+		AA+		AA(high)		High grade
Aa2		AA		AA		AA	R-1M	
Aa3		AA-		AA-		AA(low)		
A1		A+	A-1	A+	F1	A(high)	R-1L	Upper medium grade
A2		A		A		A		
A3	P-2	A-	A-2	A-	F2	A(low)		
Baa1		BBB+		BBB+		BBB(high)	R-2H	Lower medium grade
Baa2	P-3	BBB	A-3	BBB	F3	BBB	R-2M	
Baa3		BBB-		BBB-		BBB(low)	R-2L, R-3	
Ba1	Not prime	BB+	B	BB+	B	BB(high)	R-4	Non-investment grade speculative
Ba2		BB		BB		BB		
Ba3		BB-		BB-		BB(low)		
B1		B+		B+		B(high)		Highly speculative
B2		B		B		B	R-5	
B3		B-		B-		B(low)		
Caa1		CCC+	C	CCC	C	CCC(high)		Substantial risks
Caa2		CCC				CCC		
Caa3		CCC-				CCC(low)		
						CC(high)		
		CC				CC		

Source: http://en.wikipedia.org/wiki/Credit_rating

Small Cap	Under 2 Billion
Mid Cap	2 Billion to 10 Billion
Large Cap	Over 10 Billion

1 Continuity Screen
2 Sensitivity Mid Cap
3 PGE Peer Group (UE 319/PGE/1100 Villadsen/29)

1 VL #	2 Abbreviated Utility	3 UE 319 PGE	4 UE 294 PGE	5 UE 319 Staff	6 UE 294 Staff	7 VL Corporate Name Electric Utility	8 SEC Edgar CIK	9 SEC Edgar SIC	10 SEC File #	11 IRS EIN #	12 Ticker	13 SNL Key	14 VL Region	15 VL 3/27/2017 Beta	16 Yahoo Fin. 3/24/2017 Beta	17 Yahoo Fin. 3/24/2017 Mkt Cap $ Billions	18 Covered by Value Line 3/3/2017 (VL)	19 VL 3/27/2017 No Div Declines 5 years	20 S&P 3/24/2017 Local LT Debt Rating	21 Credit Rating BB+ to BBB+	22 EEI 12/31/2016 80%+ Regulated Assets	23 VL 3/23/2017 LT Debt 45% - 55% of Capital	24 VL 3/23/2017 Div. Growth 5 Yr Rate Forecast > 0%
1	AEP	Yes	Yes	No	Yes	American Electric Power Company, Inc.	0000004904	4911	1-3525	13-4922640	AEP	4006321	Central	0.65	0.14	33.32	Yes	Pass	A-	Fail	80% +	52%	Yes
2	Allete	Yes	Yes	No	No	Allete, Inc.	0000066756	4931	1-3548	41-0418150	ALE	4022309	Central	0.80	0.26	3.40	Yes	Pass	BBB+	Pass	50% to 80%	42%	Yes
3	Alliant	Yes	Yes	No	No	Alliant Energy Corporation	0000352541	4931	1-9894	39-1380265	LNT	4057038	Central	0.70	0.38	9.13	Yes	Pass	A-	Fail	80% +	48%	Yes
4	Ameren	Yes	Yes	Yes	No	Ameren Corporation	0001002910	4931	1-14756	43-1723446	AEE	4007308	Central	0.70	0.29	13.63	Yes	Pass	BBB+	Pass	80% +	46%	Yes
5	Avista	No	No	No	No	Avista Corporation	0000104918	4931	1-3701	91-0462470	AVA	4057075	West	0.70	0.20	2.54	Yes	Pass	BBB	Pass	80% +	49%	Yes
6	Black Hills	No	No	No	No	Black Hills Corporation	0001130464	4911	1-31303	46-0458824	BKH	4010420	West	0.90	0.70	3.54	Yes	Pass	BBB	Pass	80% +	60%	Yes
7	CenterPoint	Yes	Yes	No	No	CenterPoint Energy, Inc.	0001130310	4911	1-31447	74-0694415	CNP	4074390	Central	0.85	0.57	11.97	Yes	Pass	A-	Fail	50% to 80%	67%	Yes
8	Cleco	No	No	No	No	Cleco Corporation	0001089819	4911	1-15759	72-1445282	CNL	4056937	Central	0.70	N/A	N/A	Yes	Pass	BBB-	Pass	80% +	40%	Yes
9	CMS	Yes	Yes	No	No	CMS Energy Corporation	0000811156	4931	1-9513	38-2726431	CMS	4004172	Central	0.65	0.12	12.63	Yes	Pass	BBB+	Pass	80% +	66%	Yes
10	Consol Ed	Yes	Yes	No	No	Consolidated Edison, Inc.	0001047862	4931	1-14514	13-3965100	ED	4057041	East	0.55	-0.03	23.89	Yes	Pass	A-	Fail	80% +	48%	Yes
11	Dominion	Yes	Yes	No	No	Dominion Resources, Inc.	0000715957	4911	1-08489	54-1229715	D	4001616	East	0.70	0.24	49.09	Yes	Pass	BBB+	Pass	50% to 80%	66%	Yes
12	DTE	Yes	Yes	No	Yes	DTE Energy Company	0000936340	4911	1-11607	38-3217752	DTE	4057044	Central	0.65	0.12	18.30	Yes	Pass	BBB+	Pass	80% +	56%	Yes
13	Duke	No	No	No	No	Duke Energy Corporation	0001326160	4931	1-32853	20-2777218	DUK	4121470	East	0.60	0.27	59.54	Yes	Pass	A-	Fail	80% +	55%	Yes
14	Edison Int'l	Yes	Yes	Yes	Yes	Edison International	0000827052	4911	1-9936	95-4137452	EIX	4056943	West	0.65	0.11	26.26	Yes	Pass	BBB+	Pass	80% +	45%	Yes
15	El Paso	Yes	Yes	Yes	No	El Paso Electric Company	0000031978	4911	1-14206	74-0607870	EE	4056943	West	0.70	0.45	2.01	Yes	Pass	BBB	Pass	80% +	54%	Yes
16	Empire	No	No	No	No	Empire District Electric Company	0000032689	4911	1-3368	44-0236370	EDE	3005475	Central	0.70	0.63	1.14	Yes	Pass	BBB	Pass	80% +	50%	Yes
17	Entergy	Yes	Yes	No	No	Entergy Corporation	0000065984	4911	1-11299	72-1229752	ETR	4007889	Central	0.65	0.67	13.78	Yes	Pass	BBB+	Pass	80% +	63%	Yes
18	Eversource	No	No	No	No	**Eversource Energy** (formerly: ***Northeast Utilities***)	0000072741	4911	1-5324	04-2147929	ES	4057052	East	0.75	0.23	19.01	Yes	Pass	A	Fail	80% +	47%	Yes
19	Exelon	No	No	No	No	Exelon Corporation	0001109357	4931	1-16169	23-2990190	EXC	4057056	East	0.70	0.38	33.38	Yes	Fail	BBB	Pass	Under 50%	52%	Yes
20	First Energy	No	No	No	No	FirstEnergy Corporation (Formerly in part: Allegheny)	0001031296	4911	333-21011	34-1843785	FE	4056944	East	0.65	0.26	13.85	Yes	Fail	BBB-	Pass	50% to 80%	60%	Yes
21	Great Plains	No	Yes	No	Yes	Great Plains Energy Inc.	0001143068	4911	1-32206	43-1916803	GXP	4057005	Central	0.75	0.19	6.22	Yes	Pass	BBB+	Pass	80% +	39%	Yes
22	Hawaiian	No	No	No	No	Hawaiian Electric Industries, Inc.	0000354707	4911	1-8503	99-0208097	HE	1031123	West	0.70	0.39	3.66	Yes	Pass	BBB-	Pass	Under 50%	46%	Yes
23	IDACORP	Yes	Yes	Yes	Yes	IDACORP, Inc.	0001057877	4911	1-14465	82-0505802	IDA	4056949	West	0.75	0.31	4.19	Yes	Pass	BBB	Pass	80% +	47%	Yes
24	Integrys	No	No	No	No	Integrys Energy Group, Inc.	0000916863	4931	1-11337	39-1775292	TEG	N/A	N/A	0.80	N/A	N/A	Yes	Pass	A-	Fail	N/A	50%	Yes
25	ITC	No	No	No	No	ITC Holdings Corp. (Transmission ONLY)	0001317630	4911	1-32576	32-0058047	ITC	4099990	Central	0.70	N/A	N/A	Yes	Pass	A-	Fail	N/A	67%	Yes
26	MGE	Yes	Yes	No	No	MGE Energy, Inc. (Madison Gas & Electric Co.)	0001161728	4900	0-4965	39-2040501	MGEE	4072883	Central	0.70	0.13	2.18	Yes	Pass	AA-	Fail	50% to 80%	36%	Yes
27	NextEra	No	No	No	No	NextEra Energy, Inc. (Formerly: FPL Group, Inc.)	0000753308	4911	1-8841	59-2449419	NEE	3010401	East	0.65	0.31	62.10	Yes	Pass	A-	Fail	50% to 80%	51%	Yes
28	NorthWestern	No	No	No	No	NorthWestern Corporation	0000073088	4931	1-10499	46-0172280	NWE	4057053	West	0.70	0.27	2.84	Yes	Pass	BBB	Pass	80% +	53%	Yes
29	OGE	Yes	Yes	No	No	OGE Energy Corporation	0001021635	4911	1-12579	73-1481638	OGE	4057055	Central	0.95	0.82	7.13	Yes	Pass	A-	Fail	80% +	45%	Yes
30	Otter Tail	Yes	Yes	No	Yes	Otter Tail Corporation	0001466593	4911	0-53713	27-0383995	OTTR	4057017	Central	0.85	0.51	1.48	Yes	Pass	BBB	Pass	80% +	41%	Yes
31	Pepco	No	No	No	No	Pepco Holdings, Inc.	0001135971	4931	1-31403	52-2297449	POM	4078763	East	0.75	N/A	N/A	Yes	Pass	BBB+	Pass	N/A	53%	No
32	PG&E	Yes	Yes	Yes	Yes	PG&E Corporation	0001004980	4931	1-12609	94-3234914	PCG	4057057	West	0.65	0.15	34.46	Yes	Pass	BBB+	Pass	80% +	49%	Yes
33	PGE	Yes	Yes	No	No	**Portland General Electric Company**	0000784977	4911	1-05532-99	93-0256820	POR	4057019	West	0.70	0.14	4.00	Yes	Pass	BBB	Pass	80% +	51%	Yes
34	Pinnacle	Yes	Yes	No	No	Pinnacle West Capital Corporation	0000764622	4911	1-8962	86-0512431	PNW	4056951	West	0.70	0.23	9.37	Yes	Pass	A-	Fail	80% +	47%	Yes
35	PNM	No	No	Yes	Yes	PNM Resources, Inc.	0001108426	4911	1-32462	85-0468296	PNM	4006880	West	0.75	0.18	2.99	Yes	Pass	BBB+	Pass	80% +	54%	Yes
36	PPL	Yes	No	No	No	PPL Corporation	0000922224	4911	1-11459	23-2758192	PPL	4057058	East	0.70	0.55	25.59	Yes	Pass	A-	Fail	80% +	63%	Yes
37	Public Serv.	Yes	Yes	No	No	Public Serv. Enterprise Group, Inc.	0000788784	4931	1-09120	22-2625848	PEG	4050911	East	0.70	0.34	22.86	Yes	Pass	BBB+	Pass	50% to 80%	45%	Yes
38	SCANA	Yes	Yes	No	No	SCANA Corporation	0000754737	4931	1-8809	57-0784499	SCG	4057061	East	0.65	0.12	9.56	Yes	Pass	BBB+	Pass	50% to 80%	57%	Yes
39	Sempra	Yes	Yes	No	No	Sempra Energy	0001032208	4932	1-14201	33-0732627	SRE	4057062	West	0.80	0.63	28.18	Yes	Pass	BBB+	Pass	50% to 80%	53%	Yes
40	Southern	No	Yes	No	No	Southern Company, The	0000092122	4911	1-3526	58-0690070	SO	4004298	East	0.55	0.04	49.97	Yes	Pass	A	Fail	80% +	57%	Yes
41	TECO	No	No	No	No	TECO Energy, Inc.	0000350563	4911	1-8180	59-2052286	TE	3010780	East	0.80	N/A	N/A	Yes	Pass	BBB+	Pass	N/A	59%	Yes
42	UIL	No	No	No	No	UIL Holdings Corporation	0001082510	4911	1-15052	06-1541045	UIL	4057523	East	0.75	N/A	N/A	Yes	Pass	N/A	Fail	80% +	58%	No
43	UNS	No	No	No	No	UNS Energy Corporation (Formerly: UniSource)	0000941138	4911	1-13739	86-0786732	UNS	4056952	West	0.75	N/A	N/A	Yes	Pass	N/A	Fail	80% +	63%	Yes
44	Vectren	Yes	Yes	No	No	Vectren Corporation	0001096385	4932	1-15467	35-2086905	VVC	4057065	Central	0.75	0.74	4.84	Yes	Pass	A-	Fail	80% +	48%	Yes
45	WEC	No	No	No	No	WEC Energy Group (formerly Wisconsin Energy)	0000783325	4931	1-09057	39-1391525	WEC	4009725	Central	0.60	-0.02	19.28	Yes	Pass	A-	Fail	80% +	51%	Yes
46	Westar	No	Yes	No	Yes	Westar Energy, Inc.	0000054507	4931	1-3523	48-0290150	WR	4057066	Central	0.70	0.35	7.27	Yes	Pass	BBB+	Pass	80% +	50%	Yes
47	Xcel	Yes	Yes	No	No	Xcel Energy, Inc.	0000072903	4931	1-3034	41-0448030	XEL	4025308	West	0.60	0.08	22.71	Yes	Pass	A-	Fail	80% +	57%	Yes
	No. of Peers:	25	27	6	9								AVG:	0.71	0.31								
				3	3	Sensitivity Mid Cap																	

Edison Electric Institute (EEI) Rate Case Summary

Regulated	80%+ of total assets are regulated
Mostly Regulated	50% to 79% of total assets are regulated
Diversified	Less than 50% of total assets are regulated

http://www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/QtrlyFinancialUpdates/Documents/QFU_Rate_Case/

Developments:
CH Energy Group, Inc. was removed in this rate case after purchase completed by Fortis.
NV Energy Inc. was removed in this rate case after purchase completed by Berkshire Energy.
Northeast Utilities renamed itself Eversource Energy.
Wisconsin Energy Group emerged from M&A activity as WEC Energy Group.
Value Line says understatedly, "The year that just ended was an active one for deal making."
(See Many other Mergers and Acquisitions above, some of which are still working toward final approvals ar

Small Cap	Under 2 Billion
Mid Cap	2 Billion to 10 Billion
Large Cap	Over 10 Billion

1	2	3	4	5	6	25	26	
VL #	Abbreviated Utility	UE 319 PGE	UE 294 PGE	UE 319 Staff	UE 294 Staff	No M&A Detected Activity in Last 5 Years	News and Presentations	#
1	AEP	Yes	Yes	No	Yes	Nov 1999 Merged w CSR, May 2011 Float, but 5 years have passed.		1
2	Allete	Yes	Yes	No	No	Feb, 2015 1st Water Purchase $168M = U.S. Water Services Inc Δstrategy	Purchase of US Water Services, Inc – Feb. 2, 2015 / Moody's (Credit Outlook)	2
3	Alliant	Yes	Yes	No	No	Selling MN Electric & N Gas Dist to Coop Group Announced Apr. 17, 2014 SNL	Proposed $119 Deal per SNL, but with many variables not yet approved by MN PUC	3
4	Ameren	Yes	Yes	Yes	No	Mar 2013,$900M Sale of Merch. Gen. (5 Power Plants) to Dynergy / SNL	Ameren is selling 4.1 GW Coal Gen w No $ Down to Dynergy / WSJ Apr 2 2013, Div Cut in 2009, but now has 7 yrs Div Growth.	4
5	Avista	No	No	No	No	M&A - Purchase of AERC Completed 2014 after Sale of Ecova Completed	AVA acquired AERC in Mid 2014	5
6	Black Hills	No	No	No	No	Black Hills to buy MGTC transmission & distribution utility assets / SNL 2014	Acquired SourceGas which provides gas to 400,000 customers in 4 states in 2016	6
7	CenterPoint	Yes	Yes	No	No	CenterPoint Unlikely to Acquire Cleco / SNL 2014		7
8	Cleco	No	No	No	No	Macquarie (MIRA) and bcIMC led Investor Group bought CNL $4.7B, 4/13/2016	Macquarie Investors included Joh Hancock Financial	8
9	CMS	Yes	Yes	No	No	No M&A		9
10	Consol Ed	Yes	Yes	No	No	No M&A		10
11	Dominion	Yes	Yes	No	No	Questar Acquisition	Purchased Questar 2016 $4.4B (Salt Lake City, Natural Gas Utility)	11
12	DTE	Yes	Yes	No	Yes	Mar 2001 Merged w MCN	Purchased M3/Vega Midstream Gas Assets for $1.3B in 2016	12
13	Duke	No	No	No	No	Jan 2011 Bought Progress Energy	Purchased Piedmond (Large Gas Utility) in 2016	13
14	Edison Int'l	Yes	Yes	Yes	Yes	Aug 2000 Bought Citizens Power	As the holding company for Southern CA Edison (SCE) – San Onofre nuclear station (SONGS)	14
15	El Paso	Yes	Yes	Yes	No	No M&A	No Dividend prior to 2011, however now has a 5 year history of growing dividends.	15
16	Empire	No	No	No	No	Acquisition by Algonquin in 2017 per VL for C$3.4B	Reduced Dividend by Half in 2011, but now has 5 years Div Growth.	16
17	Entergy	Yes	Yes	No	No	Mar 2013 Merger w FPL Group, Dec 2011 Sold Trans. to ITC	ITC Proposed Acquisition Entergy Transmission Assets Rejected by MI PSC. Entergy to buy Union gas plant $948M SNL Mar 2015	17
18	Eversource	No	No	No	No	Oct 2010 Merged w NSTAR	Name Change, Formerly Northeast Utilities — Eversource seeks to merge select component utilities to capture A&G synergies.	18
19	Exelon	No	No	No	No	Exelon Purchase of Pepco completed Mar 25 2016, SNL	Reduced Dividend by 41% in 2013. Exelon completed $6.8B purchase of Pepco in 2016/VL.	19
20	First Energy	No	No	No	No	No M&A	Reduced Dividend by 35% in 2014	20
21	Great Plains	No	Yes	No	Yes	Great Plains to purchase Westar for $8.6B in 2017 / SNL	Reduced Dividend by Half in 2009	21
22	Hawaiian	No	No	No	No	Proposed Sale of HECO to Next Era for $4.3B / SNL Feb. 2, 2015		22
23	IDACORP	Yes	Yes	Yes	Yes	No M&A		23
24	Integrys	No	No	No	No	Wisconsin Energy to Buy Integrys Energy Group - Req. 2 Reg. Approvals	Purchase by Wisconsin Energy Approved by Integrys Shareholders / VL — See WEC	24
25	ITC	No	No	No	No	ITC Bought by Fortis Inc. and GIC Private Limited on Oct. 14, 2016	Change of BOD after Purchase by Fortis	25
26	MGE	Yes	Yes	No	No	No M&A		26
27	NextEra	No	No	No	No	Proposed Sale of HECO to Next Era for $4.3B / SNL Feb. 2, 2015 Failed	Next Era Proposes to Buy Oncor for $17B in 2017, TX PUC not seeing benefit to customers / MegaWatts Daily as of Mar 31 2017	27
28	NorthWestern	No	No	No	No	2014 Acquisition $900M to buy 633 MW Hydro Capacity in MT		28
29	OGE	Yes	Yes	No	No	No M&A		29
30	Otter Tail	Yes	Yes	No	Yes	No M&A		30
31	Pepco	No	No	No	No	Exelon Purchase of Pepco Announced May 7, 2014 $6.83 Billion SNL	Moody's Upgrades Pepco, Affirms Exelon on Merger Completion Mar 25, 2016 SNL	31
32	PG&E	Yes	Yes	Yes	Yes	July 1997 Purchased Valero Energy		32
33	PGE	Yes	Yes	No	No	No M&A		33
34	Pinnacle	Yes	Yes	No	No	Pinnacle W's AZ Pub Service (APS) Buying $182 M 4-Corners Coal Gen	Pinnacle payed 1 of 4 2013 dividends early in 2012 – Dividend trend is still increasing and passes screen	34
35	PNM	No	No	Yes	Yes	PNM 2001 Merger w Western Resources — No current M&A	Dividend fell in 2007 and fell again in 2008 - But now over 5 years of Dividend Growth.	35
36	PPL	Yes	No	No	No	Acquisition of Kentucky Utiliities and Louisville Gas & Electric Nov 2010, over 5 yrs ago.		36
37	Public Serv.	Yes	Yes	No	No	No M&A		37
38	SCANA	Yes	Yes	No	No	SCANA Feb 2015 closed the $150 million sale of SCANA Communications to Spirit	Mar 2017 Westinghouse (Div of Toshiba) US Bankruptcy leaves Scana responsible for massive cost on 2 unfinished Nuc plants.	38
39	Sempra	Yes	Yes	No	No	No M&A		39
40	Southern	No	Yes	No	No	Purchased AGL (Large Gas Utility) in 2016, renamed to Southern Gas	Mar 2017 Westinghouse (Div of Toshiba) US Bankruptcy leaves Southern responsible for massive cost on 2 unfinished Nuc plants.	40
41	TECO	No	No	No	No	TECO gets NM Gas for $950M 2014. Emera Sells Algonquin to buy TECO 2016.	July 6, 2016 Moody's downgrades TECO and Tampa Electric Co. Ratings upon Emera Acquisition Close	41
42	UIL	No	No	No	No	UIL Called Off Deal to Acquire Philadelphia Gas Works for $1.86B	Iberdrola to buy UIL for $3B after Reg. Approval, Reuters Dec. 9, 2015	42
43	UNS	No	No	No	No	Fortis to Acquire UNS for $4.3B in Q1 2015	Canadian-based Fortis, Inc. expects to complete acquisition of UNS before end of Jan. 2015.	43
44	Vectren	Yes	Yes	No	No	No M&A		44
45	WEC	No	No	No	No	Name Change, Formerly: Wisconsin Energy Group	Acquisition of Integrys $4.6B in Common & $1.5B Cash w Name Change to WEC in Jun 2015 / VL	45
46	Westar	No	Yes	No	Yes	Great Plains to purchase Westar for $8.6B in 2017 / SNL		46
47	Xcel	Yes	Yes	No	No	No M&A		47
	No. of Peers:	25	27	6	9			
				3	3			

ıd some hitting obstacles creating uncertainty.)

Value Line
Historical and Near Term
Dividends Declared per Share
(Div)

Value Line Estimated Dividends

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Screen #	Abbreviated Utility	UE 319 PGE	UE 319 Staff	2012 Q1	2012 Q2	2012 Q3	2012 Q4	2012 Yr	2013 Q1	2013 Q2	2013 Q3	2013 Q4	2013 Yr	2014 Q1	2014 Q2	2014 Q3	2014 Q4	2014 Yr	2015 Q1	2015 Q2	2015 Q3	2015 Q4	2015 Yr
1	1	AEP	**Yes**	No	0.47	0.47	0.47	0.47	**1.88**	0.47	0.49	0.49	0.50	**1.95**	0.50	0.50	0.50	0.53	**2.03**	0.53	0.53	0.53	0.56	**2.15**
2	2	Allete	**Yes**	No	0.46	0.46	0.46	0.46	**1.84**	0.475	0.475	0.475	0.475	**1.90**	0.49	0.49	0.49	0.49	**1.96**	0.505	0.505	0.505	0.505	**2.02**
3	3	Alliant	**Yes**	No	0.225	0.225	0.225	0.225	**0.90**	0.235	0.235	0.235	0.235	**0.94**	0.255	0.255	0.255	0.255	**1.02**	0.275	0.275	0.275	0.275	**1.10**
4	4	Ameren	**Yes**	**Yes**	0.40	0.40	0.40	0.40	**1.60**	0.40	0.40	0.40	0.40	**1.60**	0.40	0.40	0.40	0.41	**1.61**	0.41	0.41	0.41	0.425	**1.66**
5	7	CenterPoint	**Yes**	No	0.2025	0.2025	0.2025	0.2025	**0.81**	0.2075	0.2075	0.2075	0.2075	**0.83**	0.238	0.238	0.238	0.238	**0.95**	0.247	0.247	0.248	0.248	**0.99**
6	9	CMS	**Yes**	No	0.24	0.24	0.24	0.24	**0.96**	0.255	0.255	0.255	0.255	**1.02**	0.27	0.27	0.27	0.27	**1.08**	0.29	0.29	0.29	0.29	**1.16**
7	10	Consol Ed	**Yes**	No	0.605	0.605	0.605	0.605	**2.42**	0.615	0.615	0.615	0.615	**2.46**	0.63	0.63	0.63	0.63	**2.52**	0.65	0.65	0.65	0.65	**2.60**
8	11	Dominion	**Yes**	No	0.5275	0.5275	0.5275	0.5275	**2.11**	0.5625	0.5625	0.5625	0.5625	**2.25**	0.60	0.60	0.60	0.60	**2.40**	0.6475	0.6475	0.6475	0.6475	**2.59**
9	12	DTE	**Yes**	No	0.5875	0.5875	0.5875	0.62	**2.38**	0.62	0.62	0.655	0.655	**2.55**	0.655	0.655	0.655	0.69	**2.66**	0.69	0.69	0.69	0.73	**2.80**
10	14	Edison Int'l	**Yes**	**Yes**	0.325	0.325	0.325	0.325	**1.30**	0.3375	0.3375	0.3375	0.3375	**1.35**	0.355	0.355	0.355	0.355	**1.42**	0.418	0.418	0.418	0.418	**1.67**
11	15	El Paso	**Yes**	**Yes**	0.22	0.25	0.25	0.25	**0.97**	0.25	0.265	0.265	0.265	**1.05**	0.265	0.28	0.28	0.28	**1.11**	0.28	0.295	0.295	0.295	**1.17**
12	17	Entergy	**Yes**	No	0.83	0.83	0.83	0.83	**3.32**	0.83	0.83	0.83	0.83	**3.32**	0.83	0.83	0.83	0.83	**3.32**	0.83	0.83	0.83	0.85	**3.34**
13	23	IDACORP	**Yes**	**Yes**	0.33	0.33	0.33	0.38	**1.37**	0.38	0.38	0.38	0.43	**1.57**	0.43	0.43	0.43	0.47	**1.76**	0.47	0.47	0.47	0.51	**1.92**
14	26	MGE	**Yes**	No	0.2551	0.2551	0.2634	0.2634	**1.04**	0.2634	0.2634	0.2717	0.2717	**1.07**	0.2717	0.2717	0.2825	0.2825	**1.11**	0.2825	0.2825	0.295	0.295	**1.16**
15	29	OGE	**Yes**	No	0.19625	0.19625	0.19625	0.19625	**0.79**	0.20875	0.20875	0.20875	0.20875	**0.84**	0.225	0.225	0.225	0.25	**0.93**	0.25	0.25	0.25	0.275	**1.03**
16	30	Otter Tail	**Yes**	No	0.298	0.298	0.298	0.298	**1.19**	0.298	0.298	0.298	0.298	**1.19**	0.303	0.303	0.303	0.303	**1.21**	0.308	0.308	0.308	0.308	**1.23**
17	32	PG&E	**Yes**	**Yes**	0.455	0.455	0.455	0.455	**1.82**	0.455	0.455	0.455	0.455	**1.82**	0.455	0.455	0.455	0.455	**1.82**	0.455	0.455	0.455	0.455	**1.82**
18	33	PGE	**Yes**	**No**	0.265	0.265	0.27	0.27	**1.07**	0.27	0.27	0.275	0.275	**1.09**	0.275	0.275	0.28	0.28	**1.11**	0.28	0.28	0.30	0.30	**1.16**
19	34	Pinnacle	**Yes**	No	0.525	0.525	0.525	0.545	**2.12**	0.545	0.545	0.545	0.5675	**2.20**	0.5675	0.5675	0.5675	0.595	**2.30**	0.595	0.595	0.595	0.625	**2.41**
20	35	PNM	**No**	**Yes**	0.145	0.145	0.145	0.145	**0.58**	0.145	0.165	0.165	0.165	**0.64**	0.185	0.185	0.185	0.185	**0.74**	0.20	0.20	0.20	0.20	**0.80**
21	36	PPL	**Yes**	No					**1.44**	0.36	0.3675	0.3675	0.3675	**1.46**	0.3675	0.3725	0.3725	0.3725	**1.49**	0.37	0.37	0.37	0.38	**1.50**
22	37	Public Serv.	**Yes**	No	0.355	0.355	0.355	0.355	**1.42**	0.36	0.36	0.36	0.36	**1.44**	0.37	0.37	0.37	0.37	**1.48**	0.39	0.39	0.39	0.39	**1.56**
23	38	SCANA	**Yes**	No					**1.98**	0.495	0.5075	0.5075	0.5075	**2.02**	0.5075	0.525	0.525	0.525	**2.08**	0.53	0.55	0.55	0.55	**2.16**
24	39	Sempra	**Yes**	No	0.48	0.60	0.60	0.60	**2.28**	0.60	0.63	0.63	0.63	**2.49**	0.63	0.66	0.66	0.66	**2.61**	0.66	0.70	0.70	0.70	**2.76**
25	44	Vectren	**Yes**	No	0.35	0.35	0.35	0.355	**1.41**	0.355	0.355	0.355	0.36	**1.43**	0.36	0.36	0.36	0.38	**1.46**	0.38	0.38	0.38	0.40	**1.54**
26	47	Xcel	**Yes**	No	0.26	0.26	0.27	0.27	**1.06**	0.27	0.27	0.28	0.28	**1.10**	0.28	0.30	0.30	0.30	**1.18**	0.30	0.32	0.32	0.32	**1.26**
		No. of Peers:	25	6																				
				3	**Sensitivity Mid Cap**																			

Note: Pinacle West Issued 5 Dividends in 2012, and 3 Dividends in 2013.

1 Continuity Screen
2 Sensitivity Mid Cap
3 PGE Peer Group (UE 319/PGE/1100 Villadsen/29)

Value Line
Historical and Near Term
Dividends Declared per Share
(Div)

	1	2	3	4	25	26	27	28	29	30	31	32	33	34	35	36	37	38		
	Screen #	Abbreviated Utility	UE 319 PGE	UE 319 Staff	2016 Q1	2016 Q2	2016 Q3	2016 Q4	2016 Yr	2014-16 Average	2017 Yr	2018 Yr	2019 Yr	2020 Yr	2021 Yr	2022 Yr	VL 2020 - 22 Average	VL % Div Growth 2020 - 22 vs. 2014 - 16	Screen #	
1	1	AEP	Yes	No	0.56	0.56	0.56	0.59	2.27	2.15	2.39	2.51	2.63	2.76	2.90	3.04	2.90	5.1%	1	1
2	2	Allete	Yes	No	0.52	0.52	0.52	0.52	2.08	2.02	2.14	2.22	2.31	2.40	2.50	2.60	2.50	3.6%	2	2
3	3	Alliant	Yes	No	0.295	0.295	0.295	0.295	1.18	1.10	1.26	1.34	1.42	1.50	1.58	1.66	1.58	6.2%	3	3
4	4	Ameren	Yes	Yes	0.425	0.425	0.425	0.44	1.72	1.66	1.78	1.84	1.94	2.04	2.15	2.26	2.15	4.4%	4	4
5	7	CenterPoint	Yes	No	0.258	0.258	0.258	0.258	1.03	0.99	1.07	1.11	1.15	1.19	1.23	1.27	1.23	3.7%	7	5
6	9	CMS	Yes	No	0.31	0.31	0.31	0.31	1.24	1.16	1.33	1.42	1.51	1.60	1.70	1.80	1.70	6.6%	9	6
7	10	Consol Ed	Yes	No	0.67	0.67	0.67	0.67	2.68	2.60	2.76	2.84	2.92	3.00	3.08	3.16	3.08	2.9%	10	7
8	11	Dominion	Yes	No	0.70	0.70	0.70	0.70	2.80	2.60	3.02	3.30	3.58	3.88	4.20	4.52	4.20	8.3%	11	8
9	12	DTE	Yes	No	0.73	0.73	0.73	0.77	2.96	2.81	3.36	3.59	3.81	4.05	4.30	4.55	4.30	7.4%	12	9
10	14	Edison Int'l	Yes	Yes	0.48	0.48	0.48	0.48	1.92	1.67	2.21	2.36	2.53	2.70	2.89	3.08	2.89	9.6%	14	10
11	15	El Paso	Yes	Yes	0.30	0.31	0.31	0.31	1.23	1.17	1.30	1.41	1.52	1.65	1.78	1.91	1.78	7.3%	15	11
12	17	Entergy	Yes	No	0.85	0.85	0.85	0.87	3.42	3.36	3.50	3.58	3.65	3.73	3.80	3.87	3.80	2.1%	17	12
13	23	IDACORP	Yes	Yes	0.51	0.51	0.51	0.55	2.08	1.92	2.24	2.38	2.54	2.70	2.88	3.05	2.88	7.0%	23	13
14	26	MGE	Yes	No	0.295	0.295	0.3075	0.3075	1.21	1.16	1.25	1.30	1.35	1.40	1.45	1.50	1.45	3.8%	26	14
15	29	OGE	Yes	No	0.275	0.275	0.275	0.3025	1.13	1.03	1.27	1.40	1.51	1.62	1.75	1.88	1.75	9.3%	29	15
16	30	Otter Tail	Yes	No	0.31	0.31	0.31	0.31	1.25	1.23	1.28	1.30	1.33	1.35	1.38	1.41	1.38	1.9%	30	16
17	32	PG&E	Yes	Yes	0.455	0.455	0.49	0.49	1.89	1.84	2.08	2.27	2.48	2.70	2.95	3.20	2.95	8.2%	32	17
18	33	PGE	Yes	No	0.30	0.30	0.32	0.32	1.24	1.17	1.34	1.42	1.51	1.60	1.70	1.80	1.70	6.5%	33	18
19	34	Pinnacle	Yes	No	0.625	0.625	0.625	0.655	2.53	2.41	2.68	2.81	2.95	3.10	3.26	3.41	3.26	5.1%	34	19
20	35	PNM	No	Yes	0.22	0.22	0.22	0.22	0.88	0.81	0.97	1.07	1.18	1.30	1.43	1.56	1.43	10.0%	35	20
21	36	PPL	Yes	No	0.38	0.38	0.38	0.38	1.52	1.50	1.58	1.64	1.70	1.76	1.82	1.88	1.82	3.3%	36	21
22	37	Public Serv.	Yes	No	0.41	0.41	0.41	0.41	1.64	1.56	1.72	1.80	1.89	1.99	2.10	2.21	2.10	5.1%	37	22
23	38	SCANA	Yes	No	0.55	0.58	0.58	0.58	2.27	2.17	2.42	2.54	2.65	2.77	2.90	3.03	2.90	4.9%	38	23
24	39	Sempra	Yes	No	0.70	0.755	0.755	0.755	2.97	2.78	3.28	3.51	3.75	4.00	4.28	4.56	4.28	7.5%	39	24
25	44	Vectren	Yes	No	0.40	0.40	0.40	0.42	1.62	1.54	1.70	1.78	1.85	1.92	2.00	2.08	2.00	4.5%	44	25
26	47	Xcel	Yes	No	0.32	0.34	0.34	0.34	1.34	1.26	1.44	1.52	1.61	1.70	1.80	1.90	1.80	6.1%	47	26
		No. of Peers:	25	6														Mean		
				3													Staff Peer Screen	7.7%		
																	Staff Mid Cap Sensitivity	8.1%		
																	Company Screen	5.6%		

1 Continuity Screen
2 Sensitivity Mid Cap
3 PGE Peer Group (UE 319/PGE/1100 Villa

Value Line
Historical and Near Term
Earnings Per Share
(EPS)

Value Line Estimated EPS

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Screen #	Abbreviated Utility	UE 319 PGE	UE 319 Staff	2012 Q1	2012 Q2	2012 Q3	2012 Q4	2012 Yr	2013 Q1	2013 Q2	2013 Q3	2013 Q4	2013 Yr	2014 Q1	2014 Q2	2014 Q3	2014 Q4	2014 Yr	2015 Q1	2015 Q2	2015 Q3	2015 Q4	2015 Yr
1	1	AEP	Yes	No	0.80	0.75	1.00	0.43	**2.98**	0.75	0.73	1.10	0.60	**3.18**	1.15	0.80	1.01	0.39	**3.35**	1.27	0.88	1.04	0.41	**3.60**
2	2	Allete	Yes	No	0.66	0.39	0.78	0.75	**2.58**	0.83	0.35	0.63	0.82	**2.63**	0.80	0.40	0.97	0.73	**2.90**	0.85	0.46	1.23	0.83	**3.37**
3	3	Alliant	Yes	No	0.25	0.29	0.64	0.35	**1.53**	0.36	0.29	0.72	0.28	**1.65**	0.49	0.28	0.70	0.27	**1.74**	0.44	0.30	0.80	0.15	**1.69**
4	4	Ameren	Yes	Yes	-0.11	0.87	1.54	0.11	**2.41**	0.22	0.44	1.25	0.19	**2.10**	0.40	0.62	1.20	0.19	**2.41**	0.45	0.40	1.41	0.12	**2.38**
5	7	CenterPoint	Yes	No	0.34	0.29	0.40	0.31	**1.34**	0.34	0.29	0.35	0.26	**1.24**	0.43	0.25	0.33	0.41	**1.42**	0.30	0.18	0.34	0.26	**1.08**
6	9	CMS	Yes	No	0.36	0.37	0.55	0.25	**1.53**	0.53	0.29	0.46	0.37	**1.65**	0.75	0.30	0.34	0.36	**1.75**	0.73	0.25	0.53	0.38	**1.89**
7	10	Consol Ed	Yes	No	0.94	0.73	1.49	0.7	**3.86**	1.16	0.49	1.49	0.79	**3.93**	1.23	0.63	1.49	0.28	**3.63**	1.26	0.74	1.45	0.60	**4.05**
8	11	Dominion	Yes	No	0.86	0.48	0.80	0.61	**2.75**	0.86	0.47	1.02	0.74	**3.09**	1.03	0.60	0.95	0.46	**3.04**	0.91	0.70	1.00	0.60	**3.21**
9	12	DTE	Yes	No	0.91	0.87	1.30	0.79	**3.87**	1.34	0.60	1.13	0.70	**3.77**	1.84	0.70	0.88	1.68	**5.10**	1.53	0.61	1.47	0.83	**4.44**
10	14	Edison Int'l	Yes	Yes	0.54	0.55	1.09	2.39	**4.57**	0.78	0.78	1.41	0.81	**3.78**	0.61	1.07	1.51	1.15	**4.34**	0.91	1.15	1.15	0.94	**4.15**
11	15	El Paso	Yes	Yes	0.08	0.77	1.29	0.12	**2.26**	0.19	0.72	1.26	0.03	**2.20**	0.11	0.75	1.30	0.10	**2.26**	0.09	0.52	1.40	0.02	**2.03**
12	17	Entergy	Yes	No	0.40	2.06	1.89	1.67	**6.02**	0.90	0.92	2.31	0.83	**4.96**	2.27	1.09	1.68	0.74	**5.78**	1.65	0.83	1.90	1.43	**5.81**
13	23	IDACORP	Yes	Yes	0.50	0.71	1.84	0.33	**3.38**	0.70	0.93	1.46	0.55	**3.64**	0.55	0.89	1.73	0.69	**3.86**	0.47	1.31	1.46	0.63	**3.87**
14	26	MGE	Yes	No	0.46	0.41	0.68	0.31	**1.86**	0.65	0.40	0.70	0.41	**2.16**	0.80	0.41	0.67	0.44	**2.32**	0.53	0.39	0.82	0.32	**2.06**
15	29	OGE	Yes	No	0.19	0.47	0.94	0.19	**1.79**	0.12	0.47	1.08	0.29	**1.96**	0.25	0.50	0.94	0.29	**1.98**	0.22	0.44	0.88	0.15	**1.69**
16	30	Otter Tail	Yes	No	0.28	0.19	0.13	0.47	**1.07**	0.41	0.21	0.41	0.35	**1.38**	0.59	0.27	0.43	0.28	**1.57**	0.37	0.36	0.42	0.41	**1.56**
17	32	PG&E	Yes	Yes	0.66	0.55	0.87	-0.01	**2.07**	0.55	0.74	0.36	0.19	**1.84**	0.49	0.57	1.71	0.27	**3.04**	0.27	0.83	0.63	0.27	**2.00**
18	33	PGE	Yes	No	0.65	0.34	0.50	0.38	**1.87**	0.65	0.13	0.40	0.59	**1.77**	0.73	0.43	0.47	0.55	**2.18**	0.62	0.44	0.40	0.57	**2.03**
19	34	Pinnacle	Yes	No	-0.07	1.12	2.21	0.24	**3.50**	0.22	1.18	2.04	0.22	**3.66**	0.14	1.19	2.20	0.05	**3.58**	0.14	1.10	2.30	0.37	**3.91**
20	35	PNM	No	Yes	0.17	0.33	0.69	0.13	**1.32**	0.18	0.38	0.64	0.21	**1.41**	0.16	0.36	0.69	0.24	**1.45**	0.21	0.44	0.76	0.23	**1.64**
21	36	PPL	Yes	No					**2.61**					**2.38**	0.50	0.32	0.73	0.82	**2.37**	0.82	0.37	0.59	0.60	**2.38**
22	37	Public Serv.	Yes	No	0.97	0.42	0.68	0.37	**2.44**	0.63	0.66	0.77	0.39	**2.45**	0.76	0.42	0.87	0.94	**2.99**	1.15	0.68	0.87	0.60	**3.30**
23	38	SCANA	Yes	No					**3.15**					**3.39**	1.37	0.68	1.01	0.73	**3.79**	1.39	0.69	1.04	0.69	**3.81**
24	39	Sempra	Yes	No	0.97	0.98	1.33	1.08	**4.36**	0.54	1.46	1.09	1.13	**4.22**	0.99	1.08	1.39	1.18	**4.64**	1.74	1.03	0.99	1.47	**5.23**
25	44	Vectren	Yes	No	0.62	0.31	0.48	0.53	**1.94**	0.61	-0.07	0.52	0.60	**1.66**	0.62	0.14	0.57	0.69	**2.02**	0.69	0.43	0.48	0.79	**2.39**
26	47	Xcel	Yes	No	0.38	0.38	0.81	0.29	**1.86**	0.48	0.40	0.73	0.30	**1.91**	0.52	0.39	0.73	0.39	**2.03**	0.46	0.39	0.84	0.41	**2.10**
		No. of Peers:	25	6																				
				3	Sensitivity Mid Cap																			

1 Continuity Screen
2 Sensitivity Mid Cap
3 PGE Peer Group (UE 319/PGE/1100 Villadsen/29)

Value Line
Historical and Near Term
Earnings Per Share
(EPS)

25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46		
																					EPS		
																				VL	Div Growth		
2016	2016	2016	2016	2016	2014-16	2017	2017	2017	2017	2017	2018	2018	2018	2018	2018	2019	2020	2021	2022	2020 - 22	2020 - 22 vs.	Screen	
Q1	Q2	Q3	Q4	Yr	Average	Q1	Q2	Q3	Q4	Yr	Q1	Q2	Q3	Q4	Yr	Yr	Yr	Yr	Yr	Average	2014 - 16	#	
1.02	1.03	1.43	0.76	4.24	3.73	1.15	0.90	1.15	0.45	3.65	1.25	0.95	1.20	0.45	3.85	4.13	4.43	4.75	5.07	4.75	4.1%	1	1
0.93	0.50	0.81	0.89	3.13	3.13	0.95	0.50	1.05	0.80	3.30	1.00	0.55	1.10	0.85	3.50	3.66	3.83	4.00	4.17	4.00	4.2%	2	2
0.43	0.37	0.57	0.28	1.65	1.69	0.44	0.36	0.88	0.32	2.00	0.47	0.38	0.92	0.35	2.12	2.24	2.37	2.50	2.63	2.50	6.7%	3	3
0.43	0.61	1.52	0.13	2.69	2.49	0.45	0.65	1.50	0.20	2.80	0.50	0.70	1.55	0.25	3.00	3.16	3.32	3.50	3.68	3.50	5.8%	4	4
0.36	-0.01	0.41	0.23	0.99	1.16	0.36	0.22	0.40	0.32	1.30	0.39	0.23	0.43	0.35	1.40	1.48	1.56	1.65	1.74	1.65	6.0%	7	5
0.59	0.45	0.67	0.28	1.99	1.88	0.70	0.40	0.60	0.45	2.15	0.80	0.40	0.65	0.45	2.30	2.44	2.59	2.75	2.91	2.75	6.6%	9	6
1.05	0.78	1.48	0.64	3.95	3.88	1.20	0.75	1.55	0.65	4.15	1.25	0.78	1.60	0.67	4.30	4.45	4.59	4.75	4.91	4.75	3.4%	10	7
0.88	0.73	1.10	0.73	3.44	3.23	0.90	0.75	1.00	0.75	3.40	1.00	0.85	1.10	0.85	3.80	4.02	4.25	4.50	4.75	4.50	5.7%	11	8
1.37	0.84	1.88	0.73	4.82	4.79	1.60	1.00	1.60	1.10	5.30	1.70	1.05	1.70	1.20	5.65	5.92	6.20	6.50	6.80	6.50	5.2%	12	9
0.82	0.85	1.27	0.96	3.90	4.13	0.85	0.85	1.60	0.85	4.15	0.88	0.88	1.66	0.88	4.30	4.64	5.00	5.40	5.79	5.40	4.6%	14	10
-0.14	0.55	1.84	0.05	2.30	2.20	0.05	0.65	1.60	0.15	2.45	0.06	0.73	1.77	0.16	2.72	2.74	2.75	2.77	2.79	2.77	4.0%	15	11
1.28	3.16	2.16	0.28	6.88	6.16	1.25	1.05	1.55	1.00	4.85	1.30	1.10	1.60	1.00	5.00	5.08	5.17	5.25	5.33	5.25	-2.6%	17	12
0.51	1.12	1.65	0.62	3.90	3.88	0.61	0.97	1.90	0.57	4.05	0.67	1.04	2.04	0.61	4.36	4.43	4.50	4.58	4.65	4.58	2.8%	23	13
0.49	0.47	0.80	0.42	2.18	2.19	0.48	0.48	0.85	0.49	2.30	0.52	0.52	0.88	0.53	2.45	2.69	2.96	3.25	3.54	3.25	6.8%	26	14
0.13	0.35	0.92	0.29	1.69	1.79	0.23	0.52	1.00	0.30	2.05	0.25	0.50	1.05	0.30	2.10	2.23	2.36	2.50	2.64	2.50	5.8%	29	15
0.38	0.41	0.37	0.44	1.60	1.58	0.42	0.40	0.42	0.44	1.68	0.44	0.41	0.44	0.46	1.75	1.89	2.04	2.20	2.36	2.20	5.7%	30	16
0.22	0.46	0.77	1.45	2.90	2.65	0.85	0.75	1.30	0.75	3.65	1.19	0.81	1.40	0.81	4.21	4.23	4.25	4.28	4.30	4.28	8.3%	32	17
0.68	0.42	0.38	0.62	2.10	2.10	0.75	0.45	0.45	0.65	2.30	0.77	0.46	0.46	0.67	2.36	2.43	2.50	2.58	2.65	2.58	3.4%	33	18
0.04	1.08	2.35	0.43	3.90	3.80	0.20	1.20	2.50	0.40	4.30	0.21	1.25	2.60	0.42	4.48	4.61	4.75	4.90	5.04	4.90	4.3%	34	19
0.13	0.40	0.78	0.29	1.60	1.56	0.24	0.42	0.81	0.38	1.85	0.26	0.45	0.87	0.41	1.99	2.16	2.35	2.56	2.77	2.56	8.6%	35	20
0.71	0.71	0.69	0.68	2.79	2.51	0.70	0.45	0.55	0.50	2.20	0.70	0.50	0.55	0.55	2.30	2.44	2.59	2.75	2.91	2.75	1.5%	36	21
0.93	0.37	0.94	0.51	2.75	3.01	0.95	0.60	0.80	0.50	2.85	1.00	0.60	0.80	0.50	2.90	3.09	3.29	3.50	3.71	3.50	2.5%	37	22
1.23	0.74	1.32	0.71	4.00	3.87	1.35	0.75	1.25	0.80	4.15	1.40	0.80	1.30	0.85	4.35	4.56	4.77	5.00	5.23	5.00	4.4%	38	23
1.47	0.06	1.02	1.30	3.85	4.57	1.75	1.05	1.05	1.35	5.20	1.84	1.11	1.11	1.42	5.48	6.41	7.50	8.78	10.05	8.78	11.5%	39	24
0.58	0.39	0.74	0.84	2.55	2.32	0.64	0.43	0.75	0.88	2.70	0.70	0.46	0.78	0.91	2.85	3.04	3.24	3.45	3.66	3.45	6.8%	44	25
0.47	0.39	0.90	0.44	2.20	2.11	0.54	0.40	0.90	0.46	2.30	0.56	0.42	0.95	0.48	2.41	2.58	2.75	2.94	3.13	2.94	5.7%	47	26

	Mean
Staff Peer Screen	5.7%
Staff Mid Cap Sensitivity	5.1%
Company Screen	4.9%

Hamada Adjustment
(Drawing on Value Line and Yahoo Finance Data)

Pink Highlight Indicates 2019-2021 VL Data

$$B_U = \frac{B_L}{[1 + (1 - T_C) \times (D/E)]}$$

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
						Yahoo Finance $ Stock Closing Price 1st Trading Day of Month					VL	VL	VL Cap Structure Percentages			VL Cap Structure Percentages		
	Screen #	Abbreviated Utility	UE 319 PGE	UE 319 Staff	Ticker	Jan 1/1/2017	Feb 2/1/2017	Mar 3/1/2017	*3-Day Avg $ Stock Price*	*Div Yield at Recent Price*	*2017 Return on Common Equity*	*2020-22 Return on Common Equity*	2017 % LT Debt	2017 Common Equity	2017 Preferred Stock	2020-22 % LT Debt	2020-22 Common Equity	2020-22 Preferred Stock
1	1	AEP	Yes	No	AEP	64.06	66.97	67.39	66.14	3.6%	10.0%	11.0%	52.0	48.0	0.0	52.5	47.5	0.0
2	2	Allete	Yes	No	ALE	65.35	67.21	67.75	66.77	3.2%	8.5%	9.0%	41.5	58.5	0.0	40.0	60.0	0.0
3	3	Alliant	Yes	No	LNT	37.65	39.48	39.98	39.04	3.2%	11.0%	13.0%	50.0	48.0	2.0	50.0	48.0	2.0
4	4	Ameren	Yes	Yes	AEE	52.65	54.69	55.13	54.16	3.3%	9.5%	10.0%	47.8	51.5	0.7	48.5	50.5	1.0
5	7	CenterPoint	Yes	No	CNP	26.21	27.32	27.85	27.13	3.9%	15.5%	17.0%	67.5	32.5	0.0	65.5	34.5	0.0
6	9	CMS	Yes	No	CMS	42.60	44.52	44.82	43.98	3.0%	13.5%	13.5%	66.5	33.5	0.0	64.5	35.5	0.0
7	10	Consol Ed	Yes	No	ED	74.35	77.04	78.18	76.52	3.6%	8.5%	8.5%	46.5	53.5	0.0	45.5	54.5	0.0
8	11	Dominion	Yes	No	D	76.28	77.64	77.67	77.20	3.9%	13.5%	19.0%	67.0	33.0	0.0	61.5	38.5	0.0
9	12	DTE	Yes	No	DTE	98.64	101.38	101.78	100.60	3.3%	10.0%	10.5%	56.0	44.0	0.0	56.5	43.5	0.0
10	14	Edison Int'l	Yes	Yes	EIX	72.88	79.74	79.82	77.48	2.9%	11.0%	11.5%	45.0	46.5	8.5	45.0	48.0	7.0
11	15	El Paso	Yes	Yes	EE	45.90	48.85	49.60	48.12	2.7%	9.0%	9.5%	53.5	46.5	0.0	56.5	43.5	0.0
12	17	Entergy	Yes	No	ETR	71.64	76.66	76.19	74.83	4.7%	10.5%	10.0%	62.5	36.5	1.0	62.5	37.0	0.5
13	23	IDACORP	Yes	Yes	IDA	80.02	82.93	83.26	82.07	2.7%	9.0%	9.0%	46.5	53.5	0.0	47.0	53.0	0.0
14	26	MGE	Yes	No	MGEE	63.65	63.95	65.65	64.42	1.9%	11.0%	12.5%	36.0	64.0	0.0	36.0	64.0	0.0
15	29	OGE	Yes	No	OGE	33.54	36.83	35.40	35.26	3.6%	11.5%	12.0%	43.0	57.0	0.0	51.0	49.0	0.0
16	30	Otter Tail	Yes	No	OTTR	37.85	37.60	38.10	37.85	3.4%	9.0%	9.5%	42.0	58.0	0.0	40.0	60.0	0.0
17	32	PG&E	Yes	Yes	PCG	61.89	66.75	66.63	65.09	3.2%	10.0%	10.0%	49.0	50.5	0.5	48.0	51.5	0.5
18	33	PGE	Yes	No	POR	43.61	45.33	44.69	44.54	3.0%	8.5%	8.5%	**50.5**	**49.5**	0.0	**50.5**	**49.5**	0.0
19	34	Pinnacle	Yes	No	PNW	77.63	82.19	83.52	81.11	3.3%	10.0%	10.0%	46.5	53.5	0.0	45.0	55.0	0.0
20	35	PNM	No	Yes	PNM	34.40	36.30	37.15	35.95	2.7%	8.0%	9.5%	53.5	45.5	1.0	52.5	46.5	1.0
21	36	PPL	Yes	No	PPL	34.84	36.88	37.44	36.39	4.3%	14.0%	14.0%	63.5	36.5	0.0	58.0	42.0	0.0
22	37	Public Serv.	Yes	No	PEG	44.25	45.98	44.15	44.79	3.8%	11.0%	11.5%	43.5	56.5	0.0	47.0	53.0	0.0
23	38	SCANA	Yes	No	SCG	68.70	69.35	65.66	67.90	3.6%	10.0%	10.0%	53.5	46.5	0.0	53.5	45.5	1.0
24	39	Sempra	Yes	No	SRE	102.39	110.29	111.28	107.99	3.0%	10.0%	13.5%	53.0	47.0	0.0	57.5	42.5	0.0
25	44	Vectren	Yes	No	VVC	54.89	56.35	58.17	56.47	3.0%	12.0%	12.5%	48.0	52.0	0.0	48.0	52.0	0.0
26	47	Xcel	Yes	No	XEL	41.32	43.71	44.47	43.17	3.3%	10.0%	10.5%	57.0	43.0	0.0	52.5	47.5	0.0
		TOTALS	25	6														
				3														

Unlevered Beta = Levered Beta / (1 + ((1 – Tax Rate) x (Debt/Equity)))

Levered Beta = Unlevered Beta x (1 + ((1 – Tax Rate) x (Debt/Equity)))

Apply Greater (Most Beneficial to PGE) of 2017 vs. 2020-2022 Adjustments vs. No Hamada Adjustment

1 Continuity Screen
2 Sensitivity Mid Cap
3 PGE Peer Group (UE 319/PGE/1100 Villadsen/29)

Hamada Adjustment
(Drawing on Value Line and Yahoo Finance Data)

$$B_U = \frac{B_L}{[1+(1-T_C) \times (D/E)]}$$

	1	2	3	4	5	19	20	21	22	23	24	25	26	27	28		
	Screen #	Abbreviated Utility	UE 319 PGE	UE 319 Staff	Ticker	VL Beta	VL 2017 Tax Rate	VL 2020-22 Tax Rate	2017 Unlevered Beta	2020-22 Unlevered Beta	2017 Relevered Beta *Equity at 49.5%*	2020-22 Relevered Beta *Equity at 49.5%*	Equity Risk Premium	*Hamada 2017 Adjustment Equity at 49.5%*	*Hamada 2020-22 Adjustment Equity at 49.5%*	Screen #	
1	1	AEP	Yes	No	AEP	0.65	36.0%	36.0%	0.38	0.38	0.62	0.62	4.50%	-0.11%	-0.14%	1	1
2	2	Allete	Yes	No	ALE	0.80	20.0%	20.0%	0.51	0.52	0.91	0.93	4.50%	0.50%	0.59%	2	2
3	3	Alliant	Yes	No	LNT	0.70	15.0%	15.0%	0.36	0.36	0.67	0.67	4.50%	-0.14%	-0.14%	3	3
4	4	Ameren	Yes	Yes	AEE	0.70	38.0%	38.0%	0.44	0.44	0.71	0.70	4.50%	0.05%	0.00%	4	4
5	7	CenterPoint	Yes	No	CNP	0.85	36.0%	36.0%	0.36	0.38	0.59	0.62	4.50%	-1.15%	-1.01%	7	5
6	9	CMS	Yes	No	CMS	0.65	34.0%	34.0%	0.28	0.30	0.46	0.49	4.50%	-0.84%	-0.73%	9	6
7	10	Consol Ed	Yes	No	ED	0.55	34.0%	34.0%	0.35	0.35	0.58	0.58	4.50%	0.12%	0.15%	10	7
8	11	Dominion	Yes	No	D	0.70	30.0%	25.0%	0.29	0.32	0.49	0.55	4.50%	-0.96%	-0.66%	11	8
9	12	DTE	Yes	No	DTE	0.65	26.0%	26.0%	0.33	0.33	0.58	0.57	4.50%	-0.33%	-0.35%	12	9
10	14	Edison Int'l	Yes	Yes	EIX	0.65	25.0%	25.0%	0.35	0.36	0.61	0.62	4.50%	-0.20%	-0.12%	14	10
11	15	El Paso	Yes	Yes	EE	0.70	36.0%	36.0%	0.40	0.38	0.66	0.62	4.50%	-0.20%	-0.35%	15	11
12	17	Entergy	Yes	No	ETR	0.65	35.0%	35.0%	0.31	0.31	0.50	0.51	4.50%	-0.68%	-0.65%	17	12
13	23	IDACORP	Yes	Yes	IDA	0.75	25.0%	25.0%	0.45	0.45	0.79	0.78	4.50%	0.17%	0.14%	23	13
14	26	MGE	Yes	No	MGEE	0.70	35.0%	35.0%	0.51	0.51	0.84	0.84	4.50%	0.63%	0.63%	26	14
15	29	OGE	Yes	No	OGE	0.95	32.0%	32.0%	0.63	0.56	1.05	0.93	4.50%	0.43%	-0.10%	29	15
16	30	Otter Tail	Yes	No	OTTR	0.85	25.0%	30.0%	0.55	0.58	0.96	0.98	4.50%	0.48%	0.57%	30	16
17	32	PG&E	Yes	Yes	PCG	0.65	25.5%	27.0%	0.38	0.39	0.65	0.66	4.50%	0.00%	0.05%	32	17
18	33	PGE	Yes	No	POR	0.70	21.5%	21.5%	0.39	0.39	0.69	0.69	4.50%	-0.05%	-0.05%	33	18
19	34	Pinnacle	Yes	No	PNW	0.70	34.5%	34.5%	0.45	0.46	0.73	0.75	4.50%	0.15%	0.22%	34	19
20	35	PNM	No	Yes	PNM	0.75	35.0%	35.0%	0.42	0.43	0.69	0.70	4.50%	-0.27%	-0.21%	35	20
21	36	PPL	Yes	No	PPL	0.70	27.0%	30.0%	0.31	0.36	0.53	0.60	4.50%	-0.77%	-0.45%	36	21
22	37	Public Serv.	Yes	No	PEG	0.70	37.0%	37.0%	0.47	0.45	0.76	0.73	4.50%	0.28%	0.12%	37	22
23	38	SCANA	Yes	No	SCG	0.65	32.0%	33.0%	0.36	0.36	0.61	0.60	4.50%	-0.19%	-0.24%	38	23
24	39	Sempra	Yes	No	SRE	0.80	29.0%	28.0%	0.44	0.41	0.75	0.69	4.50%	-0.21%	-0.49%	39	24
25	44	Vectren	Yes	No	VVC	0.75	35.0%	35.0%	0.47	0.47	0.77	0.77	4.50%	0.08%	0.08%	44	25
26	47	Xcel	Yes	No	XEL	0.60	33.0%	33.0%	0.32	0.34	0.53	0.57	4.50%	-0.33%	-0.13%	47	26
		TOTALS	25	6 3													

Mean	2017	2020-22
Staff Peer Screen	0.07%	0.08%
Staff Mid Cap Sensitivity	0.10%	0.14%
Company Screen	0.13%	0.12%
Maximum Impact		0.14%

1 Continuity Screen
2 Sensitivity Mid Cap
3 PGE Peer Group (UE 319/PGE/1100 Villadsen/29)

CASE: UE 319
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 503

Staff Three Stage DCF Modeling

Exhibits in Support
of Opening Testimony

June 16, 2017

UE 319 Staff ROE Summary

Notes: OMB White House Nominal GDP Growth Yr/Yr 4.3% set in Prior Administration

CBO: Mar 2017 4.0% Nominal LT GDP Down from 4.55%. BEA Nominal Hist. Avg 5.46% Up from 5.34%

Historical Real GDP 2.80% Down from 2.81% EIA 2.2% Down from 2.4% Real GDP

Stage 3 – Long-Term Annual Dividend and EPS Growth Rates					
Component	Real Rate	TIPS Inflation Forecast	Nominal Rate	Weight	Weighted Rate
EIA	2.20%	2.04%	4.28%	12.50%	0.54%
OMB - 10 Year GDP Projection			4.10%	12.50%	0.51%
White House Obama 2017 Budget			4.30%	12.50%	0.54%
CBO Projections			4.00%	12.50%	0.50%
Historical 1980 Q1 – 2016 Q3	2.80%	2.04%	4.90%	50.0%	2.45%
Composite				100%	4.53%
BEA Average Nominal Historical 1980-2016			5.46%	100.00%	5.46%
Indiana U – Kelley 2018-35 Ctr Econometric Research	2.90%	2.04%	5.00%	100.0%	5.00%
Blue Chip* – Top 10% 2019 Values	2.90%	2.04%	5.00%	100.0%	Same

Change Drivers

A. Historical GDP rose 6 bps after inclusion of creative works, etc. back to 1929.

B. Global expectation of inflation dropped, except in certain emerging market nations.
C. No delayed productivity surge followed the 2008 downturn.
D. US birth rates declined sharply from pre-2008, while imigration reform remains controversial.
E. Global stresses and low inflation delay Fed raising of interest rates.

F. Global investor flight to safety/quality continues.
G. Change in American Presidency
H. Investors have bid up the share price of US IOUs amid recurring global uncertainties.

Effect: Narrowing expectations and lower highest expected GDP growth

Possible increases in growth are as yet unsupported — See WSJ article, "Different President, Same Economy"

	Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity					
	X	Composite Growth	4.53%	Top-10 LT Blue Chip Growth	5.00%	Nominal Historical Growth	5.46%
1	Staff Peer Screen	8.25%		8.65%		9.05%	
2	Staff Mid Cap Sensitivity	8.11%		8.52%		8.92%	
3	Company Screen	8.28%		8.68%		9.09%	

Hamada Adjustments →

Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity (Hamada Adjusted)							
X	Composite Growth	4.53%	Top-10 LT Blue Chip Growth	5.00%	Nominal Historical Growth	5.46%	
Staff Peer Screen	8.33%		8.73%		9.13%		1
Staff Mid Cap Sensitivity	8.25%		8.66%		9.06%		2
Company Screen	8.41%		8.81%		9.22%		3

	Model Y: 3 Stage DCF - Dividend Growth with Terminal Value as Sales based upon EPS Growth and Terminal Stock Sale						
	Y	Composite Growth	4.53%	Top-10 LT Blue Chip Growth	5.00%	Nominal Historical Growth	5.46%
1	Staff Peer Screen	8.39%		8.75%		9.11%	
2	Staff Mid Cap Sensitivity	8.20%		8.56%		8.92%	
3	Company Screen	8.53%		8.90%		9.25%	

Hamada Adjustments →

Model Y: 3 Stage DCF - Dividend & EPS Growth with Terminal Value as Stock Sale (Hamada Adjusted)							
Y	Composite Growth	4.53%	Top-10 LT Blue Chip Growth	5.00%	Nominal Historical Growth	5.46%	
Staff Peer Screen	8.47%		8.83%		9.19%		1
Staff Mid Cap Sensitivity	8.34%		8.70%		9.06%		2
Company Screen	8.66%		9.03%		9.38%		3

Staff does NOT use current Presidential "Blueprint" of 4.0 percent LT Real GPD growth.

Common Stock Flotation Costs Adjustment Shifts Range of Reasonable ROE's Upward by : 12.5 bps

Hamada Adjusted 3-Stage-DCF Model Results	8.38%	to	9.51%	ROE
Staff Range of Reasonable ROEs	9.0%	to	9.3%	ROE

Midpoint of Best Fit Modeling Results 9.2% ROE

(Staff's informed judgement excludes some of the lower range of modeling results depicted above)

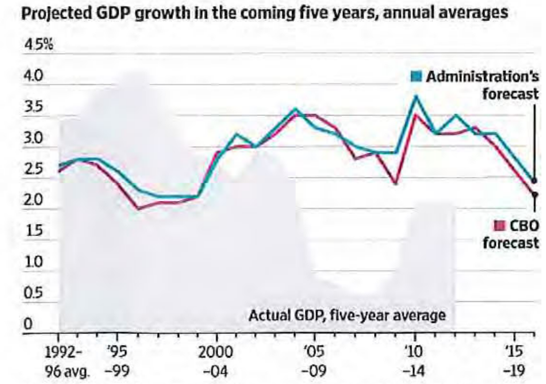
Staff Opening Testimony Point ROE Recommendation: 9.2% ROE

Usual Historical Gap White House vs CBO

Bullish Pulpit

The White House typically has slightly more optimistic growth forecasts than those from the nonpartisan Congressional Budget Office because the administration assumes its preferred policies become law.

Projected GDP growth in the coming five years, annual averages



Note: All figures adjusted for inflation; forecasts are based on either the first projections in the first half of the year, or in December of the previous year.
Sources: Congressional Budget Office (CBO), Office of Management and Budget (administration); Commerce Department (actual) THE WALL STREET JOURNAL.

While CBO is lowering — not raising LT GDP Growth

See:

"Trump Team's Growth Forecasts Far Rosier than Those of CBO, Private Economists" by Nick Timiraos WSJ February 17, 2017

This value is provided by the White House without support at this time.
No current economic indicators reflect higher that long run historical GDP growth.

The 2018 White House Budget released this May does not provide traditional without reservations. At this time, Staff recommends the Commission see the President's budget as aspirational, rather than data driven.

Please see Staff/210 Muldoon/109 for more detailed news on the gap between CBO and White House projections.

4.53% Annual Growth Rate - Stage 3 **Dividend Growth with Terminal Value as Perpetuity**

E.O.Y. Cash Flows Staff Model X

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
									2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	Screen #	Abbreviated Utility	UE 319 PGE	UE 319 Staff	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	Initial Stage					Transition Stage				
1	1	AEP	Yes	No	8.4%	35.2%	0.00	(66.14)	2.39	2.51	2.63	2.76	2.90	3.04	3.29	3.53	3.74	3.91
2	2	Allete	Yes	No	7.8%	41.3%	0.00	(66.77)	2.14	2.22	2.31	2.40	2.50	2.60	2.79	2.97	3.13	3.27
3	3	Alliant	Yes	No	8.2%	37.7%	0.00	(39.04)	1.26	1.34	1.42	1.50	1.58	1.66	1.82	1.96	2.08	2.18
4	4	Ameren	Yes	Yes	8.0%	38.9%	0.00	(54.16)	1.78	1.84	1.94	2.04	2.15	2.26	2.44	2.60	2.75	2.88
5	7	CenterPoint	Yes	No	8.5%	34.4%	0.00	(27.13)	1.07	1.11	1.15	1.19	1.23	1.27	1.37	1.45	1.53	1.60
6	9	CMS	Yes	No	8.0%	39.2%	0.00	(43.98)	1.33	1.42	1.51	1.60	1.70	1.80	1.97	2.13	2.26	2.36
7	10	Consol Ed	Yes	No	8.0%	39.0%	0.00	(76.52)	2.76	2.84	2.92	3.00	3.08	3.16	3.38	3.58	3.77	3.94
8	11	Dominion	Yes	No	9.6%	26.9%	0.00	(77.20)	3.02	3.30	3.58	3.88	4.20	4.52	5.02	5.46	5.83	6.09
9	12	DTE	Yes	No	8.4%	35.4%	0.00	(100.60)	3.36	3.59	3.81	4.05	4.30	4.55	5.02	5.44	5.78	6.05
10	14	Edison Int'l	Yes	Yes	8.1%	39.5%	0.00	(77.48)	2.21	2.36	2.53	2.70	2.89	3.08	3.44	3.77	4.03	4.21
11	15	El Paso	Yes	Yes	8.0%	40.5%	0.00	(48.12)	1.30	1.41	1.52	1.65	1.78	1.91	2.11	2.29	2.43	2.54
12	17	Entergy	Yes	No	8.8%	30.8%	0.00	(74.83)	3.50	3.58	3.65	3.73	3.80	3.87	4.11	4.34	4.56	4.77
13	23	IDACORP	Yes	Yes	7.7%	42.5%	0.00	(82.07)	2.24	2.38	2.54	2.70	2.88	3.05	3.36	3.63	3.86	4.03
14	26	MGE	Yes	No	6.5%	58.5%	0.00	(64.42)	1.25	1.30	1.35	1.40	1.45	1.50	1.61	1.72	1.82	1.90
15	29	OGE	Yes	No	9.2%	29.7%	0.00	(35.26)	1.27	1.40	1.51	1.62	1.75	1.88	2.10	2.29	2.45	2.56
16	30	Otter Tail	Yes	No	7.6%	42.8%	0.00	(37.85)	1.28	1.30	1.33	1.35	1.38	1.41	1.49	1.57	1.65	1.73
17	32	PG&E	Yes	Yes	8.8%	33.1%	0.00	(65.09)	2.08	2.27	2.48	2.70	2.95	3.20	3.55	3.85	4.11	4.30
18	33	PGE	Yes	No	8.0%	39.7%	0.00	(44.54)	1.34	1.42	1.51	1.60	1.70	1.80	1.97	2.13	2.26	2.36
19	34	Pinnacle	Yes	No	8.1%	38.3%	0.00	(81.11)	2.68	2.81	2.95	3.10	3.26	3.41	3.70	3.97	4.20	4.39
20	35	PNM	No	Yes	8.4%	37.1%	0.00	(35.95)	0.97	1.07	1.18	1.30	1.43	1.56	1.75	1.92	2.06	2.15
21	36	PPL	Yes	No	8.9%	31.0%	0.00	(36.39)	1.58	1.64	1.70	1.76	1.82	1.88	2.02	2.14	2.26	2.36
22	37	Public Serv.	Yes	No	8.7%	32.8%	0.00	(44.79)	1.72	1.80	1.89	1.99	2.10	2.21	2.39	2.56	2.71	2.84
23	38	SCANA	Yes	No	8.3%	36.2%	0.00	(67.90)	2.42	2.54	2.65	2.77	2.90	3.03	3.28	3.51	3.71	3.88
24	39	Sempra	Yes	No	8.2%	38.0%	0.00	(107.99)	3.28	3.51	3.75	4.00	4.28	4.56	5.03	5.45	5.80	6.06
25	44	Vectren	Yes	No	7.6%	43.0%	0.00	(56.47)	1.70	1.78	1.85	1.92	2.00	2.08	2.24	2.40	2.53	2.65
26	47	Xcel	Yes	No	8.3%	36.6%	0.00	(43.17)	1.44	1.52	1.61	1.70	1.80	1.90	2.08	2.24	2.37	2.48

	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	
	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046			
	Final Stage																			Terminal Value	2046 Div	2046 Perpetuity	Screen #
1	4.08	4.27	4.46	4.66	4.88	5.10	5.33	5.57	5.82	6.08	6.36	6.65	6.95	7.26	7.59	7.94	8.30	8.67	9.07	263.69	9.48	254.21	1
2	3.42	3.57	3.74	3.90	4.08	4.27	4.46	4.66	4.87	5.09	5.32	5.57	5.82	6.08	6.36	6.64	6.95	7.26	7.59	262.04	7.93	254.11	2
3	2.27	2.38	2.48	2.60	2.71	2.84	2.97	3.10	3.24	3.39	3.54	3.70	3.87	4.05	4.23	4.42	4.62	4.83	5.05	156.09	5.28	150.81	3
4	3.01	3.14	3.29	3.43	3.59	3.75	3.92	4.10	4.29	4.48	4.68	4.90	5.12	5.35	5.59	5.84	6.11	6.39	6.68	214.63	6.98	207.65	4
5	1.67	1.75	1.83	1.91	2.00	2.09	2.18	2.28	2.39	2.50	2.61	2.73	2.85	2.98	3.11	3.26	3.40	3.56	3.72	107.02	3.89	103.13	7
6	2.47	2.58	2.70	2.82	2.95	3.08	3.22	3.37	3.52	3.68	3.85	4.02	4.20	4.39	4.59	4.80	5.02	5.25	5.48	176.01	5.73	170.27	9
7	4.12	4.30	4.50	4.70	4.92	5.14	5.37	5.61	5.87	6.13	6.41	6.70	7.01	7.32	7.66	8.00	8.36	8.74	9.14	298.68	9.55	289.13	10
8	6.37	6.66	6.96	7.27	7.60	7.95	8.31	8.68	9.08	9.49	9.92	10.37	10.84	11.33	11.84	12.38	12.94	13.52	14.14	321.50	14.78	306.73	11
9	6.32	6.61	6.91	7.22	7.55	7.89	8.24	8.62	9.01	9.42	9.84	10.29	10.75	11.24	11.75	12.28	12.84	13.42	14.03	406.01	14.66	391.35	12
10	4.40	4.60	4.81	5.03	5.26	5.49	5.74	6.00	6.27	6.56	6.86	7.17	7.49	7.83	8.19	8.56	8.94	9.35	9.77	313.15	10.22	302.94	14
11	2.66	2.78	2.90	3.03	3.17	3.32	3.47	3.62	3.79	3.96	4.14	4.33	4.52	4.73	4.94	5.16	5.40	5.64	5.90	193.96	6.17	187.79	15
12	4.99	5.21	5.45	5.70	5.95	6.22	6.51	6.80	7.11	7.43	7.77	8.12	8.49	8.87	9.27	9.69	10.13	10.59	11.07	292.35	11.57	280.78	17
13	4.22	4.41	4.61	4.82	5.03	5.26	5.50	5.75	6.01	6.28	6.57	6.86	7.17	7.50	7.84	8.19	8.57	8.95	9.36	327.48	9.78	317.70	23
14	1.98	2.07	2.17	2.27	2.37	2.48	2.59	2.70	2.83	2.96	3.09	3.23	3.38	3.53	3.69	3.86	4.03	4.21	4.40	249.01	4.60	244.41	26
15	2.67	2.80	2.92	3.06	3.19	3.34	3.49	3.65	3.81	3.99	4.17	4.35	4.55	4.76	4.97	5.20	5.43	5.68	5.94	145.89	6.21	139.68	29
16	1.81	1.89	1.97	2.06	2.16	2.25	2.36	2.46	2.58	2.69	2.81	2.94	3.07	3.21	3.36	3.51	3.67	3.84	4.01	146.39	4.19	142.20	30
17	4.49	4.69	4.91	5.13	5.36	5.60	5.86	6.12	6.40	6.69	6.99	7.31	7.64	7.99	8.35	8.73	9.12	9.53	9.97	267.76	10.42	257.34	32
18	2.47	2.58	2.69	2.82	2.94	3.08	3.22	3.36	3.52	3.67	3.84	4.02	4.20	4.39	4.59	4.79	5.01	5.24	5.48	178.02	5.72	172.30	33
19	4.59	4.79	5.01	5.24	5.47	5.72	5.98	6.25	6.54	6.83	7.14	7.47	7.80	8.16	8.53	8.91	9.32	9.74	10.18	322.06	10.64	311.42	34
20	2.25	2.35	2.46	2.57	2.69	2.81	2.93	3.07	3.21	3.35	3.50	3.66	3.83	4.00	4.18	4.37	4.57	4.78	4.99	147.94	5.22	142.71	35
21	2.47	2.58	2.69	2.82	2.94	3.08	3.22	3.36	3.51	3.67	3.84	4.01	4.20	4.39	4.58	4.79	5.01	5.24	5.47	143.99	5.72	138.27	36
22	2.96	3.10	3.24	3.39	3.54	3.70	3.87	4.04	4.23	4.42	4.62	4.83	5.04	5.27	5.51	5.76	6.02	6.30	6.58	179.44	6.88	172.56	37
23	4.06	4.24	4.44	4.64	4.85	5.07	5.30	5.53	5.79	6.05	6.32	6.61	6.91	7.22	7.55	7.89	8.25	8.62	9.01	269.72	9.42	260.30	38
24	6.33	6.62	6.92	7.23	7.56	7.90	8.26	8.64	9.03	9.44	9.86	10.31	10.78	11.27	11.78	12.31	12.87	13.45	14.06	435.13	14.70	420.44	39
25	2.77	2.89	3.02	3.16	3.30	3.45	3.61	3.77	3.94	4.12	4.31	4.50	4.71	4.92	5.14	5.38	5.62	5.87	6.14	221.71	6.42	215.29	44
26	2.59	2.71	2.83	2.96	3.10	3.24	3.38	3.54	3.70	3.86	4.04	4.22	4.41	4.61	4.82	5.04	5.27	5.51	5.76	172.90	6.02	166.88	47

			Mean			
TOTALS	25	6				
w Sensitivities		3	8.15%	38.60%	0.00%	Staff Peer Screen
			8.02%	40.01%	0.00%	Staff Mid Cap Sensitivity
			8.19%	38.10%	0.00%	Company Screen

B.O.Y. Cash Flows Staff Model X

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
									2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	Screen #	Abbreviated Utility	UE 319 PGE	UE 319 Staff	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	Initial Stage					Transition Stage				
1	1	AEP	Yes	No	8.6%	33.4%	0.00	(66.14)	2.51	2.63	2.76	2.90	3.04	3.29	3.53	3.74	3.91	4.08
2	2	Allete	Yes	No	7.9%	39.7%	0.00	(66.77)	2.22	2.31	2.40	2.50	2.60	2.79	2.97	3.13	3.27	3.42
3	3	Alliant	Yes	No	8.4%	35.8%	0.00	(39.04)	1.34	1.42	1.50	1.58	1.66	1.82	1.96	2.08	2.18	2.27
4	4	Ameren	Yes	Yes	8.2%	37.2%	0.00	(54.16)	1.84	1.94	2.04	2.15	2.26	2.44	2.60	2.75	2.88	3.01
5	7	CenterPoint	Yes	No	8.6%	32.8%	0.00	(27.13)	1.11	1.15	1.19	1.23	1.27	1.37	1.45	1.53	1.60	1.67
6	9	CMS	Yes	No	8.2%	37.3%	(0.00)	(43.98)	1.42	1.51	1.60	1.70	1.80	1.97	2.13	2.26	2.36	2.47
7	10	Consol Ed	Yes	No	8.1%	37.5%	0.00	(76.52)	2.84	2.92	3.00	3.08	3.16	3.38	3.58	3.77	3.94	4.12
8	11	Dominion	Yes	No	9.8%	24.8%	0.00	(77.20)	3.30	3.58	3.88	4.20	4.52	5.02	5.46	5.83	6.09	6.37
9	12	DTE	Yes	No	8.6%	33.5%	0.00	(100.60)	3.59	3.81	4.05	4.30	4.55	5.02	5.44	5.78	6.05	6.32
10	14	Edison Int'l	Yes	Yes	8.2%	37.5%	(0.00)	(77.48)	2.36	2.53	2.70	2.89	3.08	3.44	3.77	4.03	4.21	4.40
11	15	El Paso	Yes	Yes	8.1%	38.4%	0.00	(48.12)	1.41	1.52	1.65	1.78	1.91	2.11	2.29	2.43	2.54	2.66
12	17	Entergy	Yes	No	9.0%	29.4%	0.00	(74.83)	3.58	3.65	3.73	3.80	3.87	4.11	4.34	4.56	4.77	4.99
13	23	IDACORP	Yes	Yes	7.9%	40.6%	0.00	(82.07)	2.38	2.54	2.70	2.88	3.05	3.36	3.63	3.86	4.03	4.22
14	26	MGE	Yes	No	6.6%	57.0%	0.00	(64.42)	1.30	1.35	1.40	1.45	1.50	1.61	1.72	1.82	1.90	1.98
15	29	OGE	Yes	No	9.4%	27.6%	0.00	(35.26)	1.40	1.51	1.62	1.75	1.88	2.10	2.29	2.45	2.56	2.67
16	30	Otter Tail	Yes	No	7.7%	41.4%	0.00	(37.85)	1.30	1.33	1.35	1.38	1.41	1.49	1.57	1.65	1.73	1.81
17	32	PG&E	Yes	Yes	9.0%	30.9%	0.00	(65.09)	2.27	2.48	2.70	2.95	3.20	3.55	3.85	4.11	4.30	4.49
18	33	PGE	Yes	No	8.2%	37.8%	0.00	(44.54)	1.42	1.51	1.60	1.70	1.80	1.97	2.13	2.26	2.36	2.47
19	34	Pinnacle	Yes	No	8.3%	36.6%	0.00	(81.11)	2.81	2.95	3.10	3.26	3.41	3.70	3.97	4.20	4.39	4.59
20	35	PNM	No	Yes	8.6%	34.7%	0.00	(35.95)	1.07	1.18	1.30	1.43	1.56	1.75	1.92	2.06	2.15	2.25
21	36	PPL	Yes	No	9.0%	29.5%	0.00	(36.39)	1.64	1.70	1.76	1.82	1.88	2.02	2.14	2.26	2.36	2.47
22	37	Public Serv.	Yes	No	8.9%	31.0%	0.00	(44.79)	1.80	1.89	1.99	2.10	2.21	2.39	2.56	2.71	2.84	2.96
23	38	SCANA	Yes	No	8.5%	34.5%	0.00	(67.90)	2.54	2.65	2.77	2.90	3.03	3.28	3.51	3.71	3.88	4.06
24	39	Sempra	Yes	No	8.4%	36.0%	0.00	(107.99)	3.51	3.75	4.00	4.28	4.56	5.03	5.45	5.80	6.06	6.33
25	44	Vectren	Yes	No	7.8%	41.4%	0.00	(56.47)	1.78	1.85	1.92	2.00	2.08	2.24	2.40	2.53	2.65	2.77
26	47	Xcel	Yes	No	8.5%	34.7%	0.00	(43.17)	1.52	1.61	1.70	1.80	1.90	2.08	2.24	2.37	2.48	2.59

	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	
	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046			
	Final Stage																			Terminal Value	2046 Div	2046 Perpetuity	Screen #
1	4.27	4.46	4.66	4.88	5.10	5.33	5.57	5.82	6.08	6.36	6.65	6.95	7.26	7.59	7.94	8.30	8.67	9.07	9.48	263.58	9.91	253.68	1
2	3.57	3.74	3.90	4.08	4.27	4.46	4.66	4.87	5.09	5.32	5.57	5.82	6.08	6.36	6.64	6.95	7.26	7.59	7.93	262.33	8.29	254.04	2
3	2.38	2.48	2.60	2.71	2.84	2.97	3.10	3.24	3.39	3.54	3.70	3.87	4.05	4.23	4.42	4.62	4.83	5.05	5.28	155.83	5.52	150.31	3
4	3.14	3.29	3.43	3.59	3.75	3.92	4.10	4.29	4.48	4.68	4.90	5.12	5.35	5.59	5.84	6.11	6.39	6.68	6.98	214.61	7.29	207.32	4
5	1.75	1.83	1.91	2.00	2.09	2.18	2.28	2.39	2.50	2.61	2.73	2.85	2.98	3.11	3.26	3.40	3.56	3.72	3.89	107.23	4.06	103.16	7
6	2.58	2.70	2.82	2.95	3.08	3.22	3.37	3.52	3.68	3.85	4.02	4.20	4.39	4.59	4.80	5.02	5.25	5.48	5.73	175.61	5.99	169.62	9
7	4.30	4.50	4.70	4.92	5.14	5.37	5.61	5.87	6.13	6.41	6.70	7.01	7.32	7.66	8.00	8.36	8.74	9.14	9.55	299.56	9.99	289.57	10
8	6.66	6.96	7.27	7.60	7.95	8.31	8.68	9.08	9.49	9.92	10.37	10.84	11.33	11.84	12.38	12.94	13.52	14.14	14.78	319.49	15.45	304.05	11
9	6.61	6.91	7.22	7.55	7.89	8.24	8.62	9.01	9.42	9.84	10.29	10.75	11.24	11.75	12.28	12.84	13.42	14.03	14.66	404.94	15.33	389.61	12
10	4.60	4.81	5.03	5.26	5.49	5.74	6.00	6.27	6.56	6.86	7.17	7.49	7.83	8.19	8.56	8.94	9.35	9.77	10.22	312.07	10.68	301.39	14
11	2.78	2.90	3.03	3.17	3.32	3.47	3.62	3.79	3.96	4.14	4.33	4.52	4.73	4.94	5.16	5.40	5.64	5.90	6.17	193.16	6.45	186.72	15
12	5.21	5.45	5.70	5.95	6.22	6.51	6.80	7.11	7.43	7.77	8.12	8.49	8.87	9.27	9.69	10.13	10.59	11.07	11.57	293.84	12.10	281.74	17
13	4.41	4.61	4.82	5.03	5.26	5.50	5.75	6.01	6.28	6.57	6.86	7.17	7.50	7.84	8.19	8.57	8.95	9.36	9.78	326.72	10.23	316.50	23
14	2.07	2.17	2.27	2.37	2.48	2.59	2.70	2.83	2.96	3.09	3.23	3.38	3.53	3.69	3.86	4.03	4.21	4.40	4.60	249.19	4.81	244.38	26
15	2.80	2.92	3.06	3.19	3.34	3.49	3.65	3.81	3.99	4.17	4.35	4.55	4.76	4.97	5.20	5.43	5.68	5.94	6.21	145.04	6.49	138.55	29
16	1.89	1.97	2.06	2.16	2.25	2.36	2.46	2.58	2.69	2.81	2.94	3.07	3.21	3.36	3.51	3.67	3.84	4.01	4.19	146.97	4.38	142.59	30
17	4.69	4.91	5.13	5.36	5.60	5.86	6.12	6.40	6.69	6.99	7.31	7.64	7.99	8.35	8.73	9.12	9.53	9.97	10.42	266.15	10.89	255.26	32
18	2.58	2.69	2.82	2.94	3.08	3.22	3.36	3.52	3.67	3.84	4.02	4.20	4.39	4.59	4.79	5.01	5.24	5.48	5.72	177.67	5.98	171.69	33
19	4.79	5.01	5.24	5.47	5.72	5.98	6.25	6.54	6.83	7.14	7.47	7.80	8.16	8.53	8.91	9.32	9.74	10.18	10.64	321.93	11.12	310.80	34
20	2.35	2.46	2.57	2.69	2.81	2.93	3.07	3.21	3.35	3.50	3.66	3.83	4.00	4.18	4.37	4.57	4.78	4.99	5.22	146.93	5.46	141.47	35
21	2.58	2.69	2.82	2.94	3.08	3.22	3.36	3.51	3.67	3.84	4.01	4.20	4.39	4.58	4.79	5.01	5.24	5.47	5.72	144.30	5.98	138.32	36
22	3.10	3.24	3.39	3.54	3.70	3.87	4.04	4.23	4.42	4.62	4.83	5.04	5.27	5.51	5.76	6.02	6.30	6.58	6.88	179.33	7.19	172.14	37
23	4.24	4.44	4.64	4.85	5.07	5.30	5.53	5.79	6.05	6.32	6.61	6.91	7.22	7.55	7.89	8.25	8.62	9.01	9.42	269.74	9.85	259.90	38
24	6.62	6.92	7.23	7.56	7.90	8.26	8.64	9.03	9.44	9.86	10.31	10.78	11.27	11.78	12.31	12.87	13.45	14.06	14.70	433.80	15.36	418.43	39
25	2.89	3.02	3.16	3.30	3.45	3.61	3.77	3.94	4.12	4.31	4.50	4.71	4.92	5.14	5.38	5.62	5.87	6.14	6.42	221.85	6.71	215.14	44
26	2.71	2.83	2.96	3.10	3.24	3.38	3.54	3.70	3.86	4.04	4.22	4.41	4.61	4.82	5.04	5.27	5.51	5.76	6.02	172.62	6.29	166.33	47

			Mean			
TOTALS	25	6				
w Sensitivities		3	8.34%	36.54%	0.00%	Staff Peer Screen
			8.20%	37.90%	0.00%	Staff Mid Cap Sensitivity
			8.37%	36.27%	0.00%	Company Screen

Average B.O.Y. & E.O.Y. Cash Flows Model X

	1	2	3	4	5	6	7	8	9		
	Screen #	Abbreviated Utility	UE 319 PGE	UE 319 Staff	Average IRR	Terminal Value as % of NPV_{DIV}	Average 2017 - 2021 Dividend Growth Rates EOY	BOY	Average	Screen #	
1	1	AEP	Yes	No	8.5%	34.3%	5.0%	4.9%	4.9%	1	1
2	2	Allete	Yes	No	7.9%	40.5%	4.0%	4.0%	4.0%	2	2
3	3	Alliant	Yes	No	8.3%	36.8%	5.8%	5.6%	5.7%	3	3
4	4	Ameren	Yes	Yes	8.1%	38.0%	4.8%	5.3%	5.0%	4	4
5	7	CenterPoint	Yes	No	8.6%	33.6%	3.5%	3.5%	3.5%	7	5
6	9	CMS	Yes	No	8.1%	38.3%	6.3%	6.1%	6.2%	9	6
7	10	Consol Ed	Yes	No	8.1%	38.2%	2.8%	2.7%	2.8%	10	7
8	11	Dominion	Yes	No	9.7%	25.8%	8.6%	8.2%	8.4%	11	8
9	12	DTE	Yes	No	8.5%	34.4%	6.4%	6.1%	6.2%	12	9
10	14	Edison Int'l	Yes	Yes	8.1%	38.5%	6.9%	6.8%	6.9%	14	10
11	15	El Paso	Yes	Yes	8.1%	39.4%	8.2%	8.0%	8.1%	15	11
12	17	Entergy	Yes	No	8.9%	30.1%	2.1%	2.0%	2.0%	17	12
13	23	IDACORP	Yes	Yes	7.8%	41.5%	6.5%	6.4%	6.4%	23	13
14	26	MGE	Yes	No	6.5%	57.7%	3.8%	3.7%	3.7%	26	14
15	29	OGE	Yes	No	9.3%	28.6%	8.3%	7.6%	8.0%	29	15
16	30	Otter Tail	Yes	No	7.7%	42.1%	1.9%	2.0%	1.9%	30	16
17	32	PG&E	Yes	Yes	8.9%	32.0%	9.1%	8.9%	9.0%	32	17
18	33	PGE	Yes	No	8.1%	38.7%	6.1%	6.1%	6.1%	33	18
19	34	Pinnacle	Yes	No	8.2%	37.5%	5.0%	4.9%	4.9%	34	19
20	35	PNM	No	Yes	8.5%	35.9%	10.2%	10.0%	10.1%	35	20
21	36	PPL	Yes	No	9.0%	30.2%	3.6%	3.5%	3.6%	36	21
22	37	Public Serv.	Yes	No	8.8%	31.9%	5.1%	5.2%	5.2%	37	22
23	38	SCANA	Yes	No	8.4%	35.3%	4.6%	4.5%	4.5%	38	23
24	39	Sempra	Yes	No	8.3%	37.0%	6.9%	6.8%	6.8%	39	24
25	44	Vectren	Yes	No	7.7%	42.2%	4.1%	3.9%	4.0%	44	25
26	47	Xcel	Yes	No	8.4%	35.7%	5.8%	5.7%	5.7%	47	26
		TOTALS	25	6	Mean						
		w Sensitivities		3	8.25%	37.57%	7.62%	Staff Peer Screen			
					8.11%	38.96%	8.28%	Staff Mid Cap Sensitivity			
					8.28%	37.19%	5.76%	Company Screen			

5.46% Annual Growth Rate - Stage 3 EPS Growth to Determine a Sale Terminal Value **EPS Growth**

E.O.Y. Cash Flows Staff Model Y

	Screen #	Abbreviated Utility	UE 319 PGE	UE 319 Staff	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
									Initial Stage					Transition Stage				
1	1	AEP	Yes	No	9.4%	38.5%	####	(66.14)	2.39	2.51	2.63	2.76	2.90	3.04	3.32	3.59	3.84	4.05
				e					3.65	3.85	4.13	4.43	4.75	5.07	5.51	5.93	6.32	6.66
2	2	Allete	Yes	No	8.7%	43.3%	####	(66.77)	2.14	2.22	2.31	2.40	2.50	2.60	2.81	3.02	3.21	3.39
				e					3.30	3.50	3.66	3.83	4.00	4.17	4.54	4.88	5.20	5.49
3	3	Alliant	Yes	No	9.2%	40.7%	####	(39.04)	1.26	1.34	1.42	1.50	1.58	1.66	1.84	2.00	2.14	2.25
				e					2.00	2.12	2.24	2.37	2.50	2.63	2.92	3.18	3.41	3.59
4	4	Ameren	Yes	Yes	9.0%	41.7%	####	(54.16)	1.78	1.84	1.94	2.04	2.15	2.26	2.46	2.65	2.83	2.98
				e					2.80	3.00	3.16	3.32	3.50	3.68	4.04	4.39	4.69	4.95
5	7	CenterPoint	Yes	No	9.5%	37.6%	####	(27.13)	1.07	1.11	1.15	1.19	1.23	1.27	1.38	1.48	1.57	1.66
				e					1.30	1.40	1.48	1.56	1.65	1.74	1.91	2.08	2.22	2.35
6	9	CMS	Yes	No	9.1%	42.5%	#####	(43.98)	1.33	1.42	1.51	1.60	1.70	1.80	1.99	2.17	2.32	2.45
				e					2.15	2.30	2.44	2.59	2.75	2.91	3.22	3.50	3.75	3.96
7	10	Consol Ed	Yes	No	8.7%	39.9%	####	(76.52)	2.76	2.84	2.92	3.00	3.08	3.16	3.41	3.64	3.87	4.08
				e					4.15	4.30	4.45	4.59	4.75	4.91	5.31	5.69	6.05	6.38
8	11	Dominion	Yes	No	10.5%	29.9%	####	(77.20)	3.02	3.30	3.58	3.88	4.20	4.52	5.07	5.56	5.98	6.31
				e					3.40	3.80	4.02	4.25	4.50	4.75	5.22	5.66	6.05	6.38
9	12	DTE	Yes	Yes	9.3%	37.6%	####	(100.60)	3.36	3.59	3.81	4.05	4.30	4.55	5.06	5.53	5.94	6.26
				e					5.30	5.65	5.92	6.20	6.50	6.80	7.45	8.06	8.61	9.08
10	14	Edison Int'l	Yes	No	9.1%	42.8%	####	(77.48)	2.21	2.36	2.53	2.70	2.89	3.08	3.47	3.83	4.14	4.36
				e					4.15	4.30	4.64	5.00	5.40	5.79	6.31	6.81	7.26	7.65
11	15	El Paso	Yes	Yes	8.5%	40.4%	####	(48.12)	1.30	1.41	1.52	1.65	1.78	1.91	2.13	2.33	2.50	2.63
				e					2.45	2.72	2.74	2.75	2.77	2.79	3.03	3.26	3.47	3.66
12	17	Entergy	Yes	No	9.2%	29.5%	#####	(74.83)	3.50	3.58	3.65	3.73	3.80	3.87	4.15	4.42	4.69	4.94
				e					4.85	5.00	5.08	5.17	5.25	5.33	5.52	5.74	6.01	6.34
13	23	IDACORP	Yes	Yes	8.3%	42.5%	####	(82.07)	2.24	2.38	2.54	2.70	2.88	3.05	3.39	3.69	3.96	4.18
				e					4.05	4.36	4.43	4.50	4.58	4.65	5.01	5.35	5.68	6.00
14	26	MGE	Yes	No	8.1%	63.4%	####	(64.42)	1.25	1.30	1.35	1.40	1.45	1.50	1.63	1.75	1.86	1.97
				e					2.30	2.45	2.69	2.96	3.25	3.54	3.93	4.28	4.59	4.84
15	29	OGE	Yes	0	10.0%	31.7%	####	(35.26)	1.27	1.40	1.51	1.62	1.75	1.88	2.11	2.33	2.51	2.65
				e					2.05	2.10	2.23	2.36	2.50	2.64	2.90	3.15	3.37	3.55
16	30	Otter Tail	Yes	No	8.8%	46.9%	####	(37.85)	1.28	1.30	1.33	1.35	1.38	1.41	1.51	1.60	1.70	1.79
				e					1.68	1.75	1.89	2.04	2.20	2.36	2.60	2.82	3.01	3.17
17	32	PG&E	Yes	Yes	9.5%	34.3%	####	(65.09)	2.08	2.27	2.48	2.70	2.95	3.20	3.58	3.92	4.22	4.45
				e					3.65	4.21	4.23	4.25	4.28	4.30	4.81	5.28	5.68	5.99
18	33	PGE	Yes	No	8.6%	39.9%	####	(44.54)	1.34	1.42	1.51	1.60	1.70	1.80	1.99	2.16	2.32	2.44
				e					2.30	2.36	2.43	2.50	2.58	2.65	2.86	3.07	3.27	3.45
19	34	Pinnacle	Yes	No	8.8%	39.1%	####	(81.11)	2.68	2.81	2.95	3.10	3.26	3.41	3.73	4.04	4.31	4.55
				e					4.30	4.48	4.61	4.75	4.90	5.04	5.49	5.91	6.30	6.64
20	35	PNM	No	Yes	9.6%	42.0%	####	(35.95)	0.97	1.07	1.18	1.30	1.43	1.56	1.77	1.96	2.11	2.23
				e					1.85	1.99	2.16	2.35	2.56	2.77	3.11	3.41	3.67	3.87
21	36	PPL	Yes	No	9.7%	33.1%	####	(36.39)	1.58	1.64	1.70	1.76	1.82	1.88	2.03	2.18	2.32	2.44
				e					2.20	2.30	2.44	2.59	2.75	2.91	3.10	3.30	3.49	3.68
22	37	Public Serv.	Yes	No	9.5%	34.7%	####	(44.79)	1.72	1.80	1.89	1.99	2.10	2.21	2.41	2.61	2.79	2.94
				e					2.85	2.90	3.09	3.29	3.50	3.71	3.99	4.26	4.52	4.77
23	38	SCANA	Yes	No	9.1%	38.1%	####	(67.90)	2.42	2.54	2.65	2.77	2.90	3.03	3.31	3.57	3.81	4.02
				e					4.15	4.35	4.56	4.77	5.00	5.23	5.69	6.13	6.54	6.89
24	39	Sempra	Yes	No	10.2%	47.6%	####	(107.99)	3.28	3.51	3.75	4.00	4.28	4.56	5.07	5.54	5.95	6.28
				e					5.20	5.48	6.41	7.50	8.78	10.05	11.50	12.80	13.87	14.63
25	44	Vectren	Yes	No	8.8%	46.7%	####	(56.47)	1.70	1.78	1.85	1.92	2.00	2.08	2.26	2.44	2.60	2.74
				e					2.70	2.85	3.04	3.24	3.45	3.66	4.06	4.42	4.74	5.00
26	47	Xcel	Yes	No	9.3%	39.9%	####	(43.17)	1.44	1.52	1.61	1.70	1.80	1.90	2.10	2.28	2.44	2.57
				e					2.30	2.41	2.58	2.75	2.94	3.13	3.44	3.73	3.99	4.21
		TOTALS	25	6	Mean													
		w Sensitivities		3	9.00%	40.63%	0.00%	Staff Peer Screen										
					8.82%	41.63%	0.00%	Staff Mid Cap Sensitivity										
					9.15%	40.09%	0.00%	Company Screen										

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37
	Final Stage																		
1	4.27	4.50	4.75	5.01	5.28	5.57	5.87	6.19	6.53	6.89	7.26	7.66	8.08	8.52	8.98	9.48	9.99	10.54	11.11
	7.03	7.41	7.82	8.24	8.69	9.17	9.67	10.20	10.75	11.34	11.96	12.61	13.30	14.03	14.79	15.60	16.45	17.35	18.30
2	3.57	3.77	3.97	4.19	4.42	4.66	4.92	5.18	5.47	5.77	6.08	6.41	6.76	7.13	7.52	7.93	8.37	8.82	9.30
	5.79	6.10	6.44	6.79	7.16	7.55	7.96	8.40	8.86	9.34	9.85	10.39	10.95	11.55	12.18	12.85	13.55	14.29	15.07
3	2.38	2.51	2.64	2.79	2.94	3.10	3.27	3.45	3.64	3.84	4.04	4.27	4.50	4.74	5.00	5.28	5.56	5.87	6.19
	3.79	3.99	4.21	4.44	4.68	4.94	5.21	5.49	5.79	6.11	6.44	6.80	7.17	7.56	7.97	8.41	8.87	9.35	9.86
4	3.14	3.31	3.50	3.69	3.89	4.10	4.32	4.56	4.81	5.07	5.35	5.64	5.95	6.27	6.62	6.98	7.36	7.76	8.18
	5.22	5.50	5.80	6.12	6.46	6.81	7.18	7.57	7.98	8.42	8.88	9.37	9.88	10.42	10.98	11.58	12.22	12.88	13.59
5	1.75	1.85	1.95	2.05	2.17	2.28	2.41	2.54	2.68	2.82	2.98	3.14	3.31	3.49	3.68	3.89	4.10	4.32	4.56
	2.47	2.61	2.75	2.90	3.06	3.23	3.40	3.59	3.79	3.99	4.21	4.44	4.68	4.94	5.21	5.49	5.79	6.11	6.44
6	2.58	2.72	2.87	3.03	3.19	3.37	3.55	3.75	3.95	4.17	4.39	4.63	4.89	5.15	5.43	5.73	6.04	6.37	6.72
	4.18	4.40	4.64	4.90	5.16	5.45	5.74	6.06	6.39	6.74	7.10	7.49	7.90	8.33	8.79	9.27	9.77	10.31	10.87
7	4.30	4.54	4.79	5.05	5.32	5.61	5.92	6.24	6.58	6.94	7.32	7.72	8.14	8.59	9.06	9.55	10.07	10.62	11.20
	6.73	7.10	7.49	7.90	8.33	8.78	9.26	9.77	10.30	10.86	11.46	12.08	12.74	13.44	14.17	14.94	15.76	16.62	17.53
8	6.66	7.02	7.40	7.81	8.23	8.68	9.16	9.66	10.18	10.74	11.33	11.94	12.60	13.28	14.01	14.77	15.58	16.43	17.33
	6.73	7.09	7.48	7.89	8.32	8.78	9.25	9.76	10.29	10.85	11.45	12.07	12.73	13.43	14.16	14.93	15.75	16.61	17.51
9	6.61	6.97	7.35	7.75	8.17	8.62	9.09	9.58	10.11	10.66	11.24	11.85	12.50	13.18	13.90	14.66	15.46	16.31	17.20
	9.57	10.09	10.64	11.23	11.84	12.49	13.17	13.89	14.64	15.44	16.29	17.18	18.11	19.10	20.15	21.25	22.41	23.63	24.92
10	4.60	4.85	5.12	5.40	5.69	6.00	6.33	6.68	7.04	7.43	7.83	8.26	8.71	9.18	9.69	10.21	10.77	11.36	11.98
	8.07	8.51	8.98	9.47	9.98	10.53	11.10	11.71	12.35	13.02	13.74	14.49	15.28	16.11	16.99	17.92	18.90	19.93	21.02
11	2.78	2.93	3.09	3.26	3.44	3.62	3.82	4.03	4.25	4.48	4.73	4.98	5.26	5.54	5.85	6.17	6.50	6.86	7.23
	3.86	4.07	4.29	4.52	4.77	5.03	5.31	5.60	5.90	6.22	6.56	6.92	7.30	7.70	8.12	8.56	9.03	9.52	10.04
12	5.21	5.50	5.80	6.11	6.45	6.80	7.17	7.56	7.98	8.41	8.87	9.35	9.87	10.40	10.97	11.57	12.20	12.87	13.57
	6.69	7.05	7.44	7.84	8.27	8.72	9.20	9.70	10.23	10.79	11.38	12.00	12.66	13.35	14.08	14.84	15.66	16.51	17.41
13	4.41	4.65	4.90	5.17	5.45	5.75	6.06	6.39	6.74	7.11	7.50	7.91	8.34	8.80	9.28	9.78	10.32	10.88	11.47
	6.32	6.67	7.03	7.42	7.82	8.25	8.70	9.17	9.67	10.20	10.76	11.35	11.97	12.62	13.31	14.03	14.80	15.61	16.46
14	2.07	2.19	2.31	2.43	2.56	2.70	2.85	3.01	3.17	3.35	3.53	3.72	3.92	4.14	4.36	4.60	4.85	5.12	5.40
	5.10	5.38	5.67	5.98	6.31	6.66	7.02	7.40	7.81	8.23	8.68	9.16	9.66	10.18	10.74	11.33	11.94	12.60	13.28
15	2.80	2.95	3.11	3.28	3.46	3.65	3.85	4.06	4.28	4.51	4.76	5.02	5.29	5.58	5.89	6.21	6.55	6.90	7.28
	3.75	3.95	4.17	4.40	4.64	4.89	5.16	5.44	5.73	6.05	6.38	6.72	7.09	7.48	7.89	8.32	8.77	9.25	9.76
16	1.89	1.99	2.10	2.22	2.34	2.46	2.60	2.74	2.89	3.05	3.21	3.39	3.57	3.77	3.98	4.19	4.42	4.66	4.92
	3.35	3.53	3.72	3.93	4.14	4.37	4.61	4.86	5.12	5.40	5.70	6.01	6.34	6.68	7.05	7.43	7.84	8.27	8.72
17	4.69	4.95	5.22	5.50	5.80	6.12	6.46	6.81	7.18	7.57	7.99	8.42	8.88	9.37	9.88	10.42	10.99	11.59	12.22
	6.32	6.67	7.03	7.41	7.82	8.24	8.69	9.17	9.67	10.20	10.75	11.34	11.96	12.61	13.30	14.03	14.80	15.60	16.46
18	2.58	2.72	2.87	3.02	3.19	3.36	3.55	3.74	3.94	4.16	4.39	4.63	4.88	5.15	5.43	5.72	6.04	6.36	6.71
	3.63	3.83	4.04	4.26	4.50	4.74	5.00	5.27	5.56	5.86	6.18	6.52	6.88	7.25	7.65	8.07	8.51	8.97	9.46
19	4.79	5.06	5.33	5.62	5.93	6.25	6.59	6.95	7.33	7.73	8.16	8.60	9.07	9.57	10.09	10.64	11.22	11.83	12.48
	7.01	7.39	7.79	8.22	8.67	9.14	9.64	10.17	10.72	11.31	11.92	12.58	13.26	13.99	14.75	15.55	16.40	17.30	18.24
20	2.35	2.48	2.62	2.76	2.91	3.07	3.23	3.41	3.60	3.79	4.00	4.22	4.45	4.69	4.95	5.22	5.50	5.81	6.12
	4.09	4.31	4.54	4.79	5.05	5.33	5.62	5.93	6.25	6.59	6.95	7.33	7.73	8.15	8.60	9.07	9.56	10.09	10.64
21	2.58	2.72	2.87	3.02	3.19	3.36	3.55	3.74	3.94	4.16	4.39	4.62	4.88	5.14	5.42	5.72	6.03	6.36	6.71
	3.88	4.09	4.32	4.55	4.80	5.06	5.34	5.63	5.94	6.26	6.60	6.97	7.35	7.75	8.17	8.62	9.09	9.58	10.10
22	3.10	3.27	3.45	3.63	3.83	4.04	4.26	4.50	4.74	5.00	5.27	5.56	5.86	6.18	6.52	6.88	7.25	7.65	8.07
	5.03	5.30	5.59	5.90	6.22	6.56	6.92	7.29	7.69	8.11	8.56	9.02	9.52	10.04	10.58	11.16	11.77	12.41	13.09
23	4.24	4.47	4.72	4.98	5.25	5.53	5.84	6.16	6.49	6.85	7.22	7.61	8.03	8.47	8.93	9.42	9.93	10.47	11.05
	7.27	7.67	8.09	8.53	8.99	9.48	10.00	10.55	11.12	11.73	12.37	13.05	13.76	14.51	15.30	16.14	17.02	17.95	18.93
24	6.62	6.98	7.36	7.77	8.19	8.64	9.11	9.61	10.13	10.68	11.27	11.88	12.53	13.21	13.94	14.70	15.50	16.34	17.24
	15.43	16.27	17.16	18.10	19.08	20.13	21.23	22.38	23.61	24.90	26.26	27.69	29.20	30.79	32.48	34.25	36.12	38.09	40.17
25	2.89	3.05	3.22	3.39	3.58	3.77	3.98	4.19	4.42	4.67	4.92	5.19	5.47	5.77	6.09	6.42	6.77	7.14	7.53
	5.28	5.56	5.87	6.19	6.53	6.88	7.26	7.66	8.07	8.51	8.98	9.47	9.99	10.53	11.11	11.71	12.35	13.03	13.74
26	2.71	2.86	3.01	3.18	3.35	3.54	3.73	3.93	4.15	4.37	4.61	4.86	5.13	5.41	5.71	6.02	6.35	6.69	7.06
	4.44	4.68	4.94	5.21	5.49	5.79	6.11	6.44	6.79	7.16	7.56	7.97	8.40	8.86	9.35	9.86	10.39	10.96	11.56

	2046 Terminal Value	2046 Div	2046 Sale	2047	Screen #	
	38	39	40	41		
1	380.46	11.72	368.74		1	1
		19.30		20.35		
2	348.92	9.81	339.11		2	2
		15.89		16.76		
3	220.57	6.53	214.04		3	3
		10.40		10.97		
4	300.91	8.63	292.28		4	4
		14.33		15.11		
5	154.30	4.81	149.49		7	5
		6.79		7.16		
6	254.40	7.09	247.31		9	6
		11.46		12.09		
7	371.27	11.82	359.45		10	7
		18.48		19.49		
8	460.56	18.28	442.28		11	8
		18.47		19.48		
9	544.19	18.14	526.06		12	9
		26.28		27.71		
10	449.02	12.64	436.38		14	10
		22.16		23.37		
11	226.96	7.63	219.33		15	11
		10.59		11.17		
12	313.09	14.31	298.77		17	12
		18.36		19.36		
13	383.11	12.10	371.01		23	13
		17.36		18.31		
14	419.46	5.69	413.77		26	14
		14.01		14.77		
15	194.29	7.68	186.62		29	15
		10.29		10.85		
16	223.62	5.19	218.44		30	16
		9.19		9.70		
17	339.25	12.89	326.36		32	17
		17.35		18.30		
18	210.90	7.08	203.83		33	18
		9.98		10.52		
19	395.92	13.16	382.76		34	19
		19.24		20.29		
20	236.35	6.46	229.90		35	20
		11.22		11.83		
21	192.96	7.08	185.88		36	21
		10.66		11.24		
22	237.33	8.51	228.82		37	22
		13.81		14.56		
23	356.14	11.65	344.49		38	23
		19.96		21.05		
24	945.99	18.18	927.81		39	24
		42.36		44.68		
25	327.50	7.94	319.56		44	25
		14.49		15.28		
26	248.73	7.44	241.29		47	26
		12.19		12.86		

B.O.Y. Cash Flows   Staff   Model Y EPS Growth

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
	#	Abbreviated Utility	UE 319 PGE	UE 319 Staff	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
									Initial Stage					Transition Stage					Final Stage				
1	1	AEP	Yes	No	9.6%	36.5%	####	(66.14)	2.51	2.63	2.76	2.90	3.04	3.32	3.59	3.84	4.05	4.27	4.50	4.75	5.01	5.28	5.57
				e					3.65	3.85	4.13	4.43	4.75	5.07	5.51	5.93	6.32	6.66	7.03	7.41	7.82	8.24	8.69
2	2	Allete	Yes	No	8.8%	41.5%	####	(66.77)	2.22	2.31	2.40	2.50	2.60	2.81	3.02	3.21	3.39	3.57	3.77	3.97	4.19	4.42	4.66
				e					3.30	3.50	3.66	3.83	4.00	4.17	4.54	4.88	5.20	5.49	5.79	6.10	6.44	6.79	7.16
3	3	Alliant	Yes	No	9.4%	38.6%	####	(39.04)	1.34	1.42	1.50	1.58	1.66	1.84	2.00	2.14	2.25	2.38	2.51	2.64	2.79	2.94	3.10
				e					2.00	2.12	2.24	2.37	2.50	2.63	2.92	3.18	3.41	3.59	3.79	3.99	4.21	4.44	4.68
4	4	Ameren	Yes	Yes	9.2%	39.8%	####	(54.16)	1.84	1.94	2.04	2.15	2.26	2.46	2.65	2.83	2.98	3.14	3.31	3.50	3.69	3.89	4.10
				e					2.80	3.00	3.16	3.32	3.50	3.68	4.04	4.39	4.69	4.95	5.22	5.50	5.80	6.12	6.46
5	7	CenterPoint	Yes	No	9.7%	35.8%	####	(27.13)	1.11	1.15	1.19	1.23	1.27	1.38	1.48	1.57	1.66	1.75	1.85	1.95	2.05	2.17	2.28
				e					1.30	1.40	1.48	1.56	1.65	1.74	1.91	2.08	2.22	2.35	2.47	2.61	2.75	2.90	3.06
6	9	CMS	Yes	No	9.3%	40.4%	####	(43.98)	1.42	1.51	1.60	1.70	1.80	1.99	2.17	2.32	2.45	2.58	2.72	2.87	3.03	3.19	3.37
				e					2.15	2.30	2.44	2.59	2.75	2.91	3.22	3.50	3.75	3.96	4.18	4.40	4.64	4.90	5.16
7	10	Consol Ed	Yes	No	8.9%	38.1%	####	(76.52)	2.84	2.92	3.00	3.08	3.16	3.41	3.64	3.87	4.08	4.30	4.54	4.79	5.05	5.32	5.61
				e					4.15	4.30	4.45	4.59	4.75	4.91	5.31	5.69	6.05	6.38	6.73	7.10	7.49	7.90	8.33
8	11	Dominion	Yes	No	10.8%	27.6%	####	(77.20)	3.30	3.58	3.88	4.20	4.52	5.07	5.56	5.98	6.31	6.66	7.02	7.40	7.81	8.23	8.68
				e					3.40	3.80	4.02	4.25	4.50	4.75	5.22	5.66	6.05	6.38	6.73	7.09	7.48	7.89	8.32
9	12	DTE	Yes	Yes	9.5%	35.4%	####	(100.60)	3.59	3.81	4.05	4.30	4.55	5.06	5.53	5.94	6.26	6.61	6.97	7.35	7.75	8.17	8.62
				e					5.30	5.65	5.92	6.20	6.50	6.80	7.45	8.06	8.61	9.08	9.57	10.09	10.64	11.23	11.84
10	14	Edison Int'l	Yes	No	9.3%	40.5%	####	(77.48)	2.36	2.53	2.70	2.89	3.08	3.47	3.83	4.14	4.36	4.60	4.85	5.12	5.40	5.69	6.00
				e					4.15	4.30	4.64	5.00	5.40	5.79	6.31	6.81	7.26	7.65	8.07	8.51	8.98	9.47	9.98
11	15	El Paso	Yes	Yes	8.7%	38.2%	####	(48.12)	1.41	1.52	1.65	1.78	1.91	2.13	2.33	2.50	2.63	2.78	2.93	3.09	3.26	3.44	3.62
				e					2.45	2.72	2.74	2.75	2.77	2.79	3.03	3.26	3.47	3.66	3.86	4.07	4.29	4.52	4.77
12	17	Entergy	Yes	No	9.4%	28.0%	####	(74.83)	3.58	3.65	3.73	3.80	3.87	4.15	4.42	4.69	4.94	5.21	5.50	5.80	6.11	6.45	6.80
				e					4.85	5.00	5.08	5.17	5.25	5.33	5.52	5.74	6.01	6.34	6.69	7.05	7.44	7.84	8.27
13	23	IDACORP	Yes	Yes	8.5%	40.4%	####	(82.07)	2.38	2.54	2.70	2.88	3.05	3.39	3.69	3.96	4.18	4.41	4.65	4.90	5.17	5.45	5.75
				e					4.05	4.36	4.43	4.50	4.58	4.65	5.01	5.35	5.68	6.00	6.32	6.67	7.03	7.42	7.82
14	26	MGE	Yes	No	8.2%	61.9%	####	(64.42)	1.30	1.35	1.40	1.45	1.50	1.63	1.75	1.86	1.97	2.07	2.19	2.31	2.43	2.56	2.70
				e					2.30	2.45	2.69	2.96	3.25	3.54	3.93	4.28	4.59	4.84	5.10	5.38	5.67	5.98	6.31
15	29	OGE	Yes	0	10.3%	29.4%	####	(35.26)	1.40	1.51	1.62	1.75	1.88	2.11	2.33	2.51	2.65	2.80	2.95	3.11	3.28	3.46	3.65
				e					2.05	2.10	2.23	2.36	2.50	2.64	2.90	3.15	3.37	3.55	3.75	3.95	4.17	4.40	4.64
16	30	Otter Tail	Yes	No	8.9%	45.3%	####	(37.85)	1.30	1.33	1.35	1.38	1.41	1.51	1.60	1.70	1.79	1.89	1.99	2.10	2.22	2.34	2.46
				e					1.68	1.75	1.89	2.04	2.20	2.36	2.60	2.82	3.01	3.17	3.35	3.53	3.72	3.93	4.14
17	32	PG&E	Yes	Yes	9.8%	32.0%	####	(65.09)	2.27	2.48	2.70	2.95	3.20	3.58	3.92	4.22	4.45	4.69	4.95	5.22	5.50	5.80	6.12
				e					3.65	4.21	4.23	4.25	4.28	4.30	4.81	5.28	5.68	5.99	6.32	6.67	7.03	7.41	7.82
18	33	PGE	Yes	No	8.8%	37.8%	####	(44.54)	1.42	1.51	1.60	1.70	1.80	1.99	2.16	2.32	2.44	2.58	2.72	2.87	3.02	3.19	3.36
				e					2.30	2.36	2.43	2.50	2.58	2.65	2.86	3.07	3.27	3.45	3.63	3.83	4.04	4.26	4.50
19	34	Pinnacle	Yes	No	9.0%	37.1%	####	(81.11)	2.81	2.95	3.10	3.26	3.41	3.73	4.04	4.31	4.55	4.79	5.06	5.33	5.62	5.93	6.25
				e					4.30	4.48	4.61	4.75	4.90	5.04	5.49	5.91	6.30	6.64	7.01	7.39	7.79	8.22	8.67
20	35	PNM	No	Yes	9.8%	39.5%	####	(35.95)	1.07	1.18	1.30	1.43	1.56	1.77	1.96	2.11	2.23	2.35	2.48	2.62	2.76	2.91	3.07
				e					1.85	1.99	2.16	2.35	2.56	2.77	3.11	3.41	3.67	3.87	4.09	4.31	4.54	4.79	5.05
21	36	PPL	Yes	No	9.9%	31.3%	####	(36.39)	1.64	1.70	1.76	1.82	1.88	2.03	2.18	2.32	2.44	2.58	2.72	2.87	3.02	3.19	3.36
				e					2.20	2.30	2.44	2.59	2.75	2.91	3.10	3.30	3.49	3.68	3.88	4.09	4.32	4.55	4.80
22	37	Public Serv.	Yes	No	9.7%	32.7%	####	(44.79)	1.80	1.89	1.99	2.10	2.21	2.41	2.61	2.79	2.94	3.10	3.27	3.45	3.63	3.83	4.04
				e					2.65	2.90	3.09	3.29	3.50	3.71	3.99	4.26	4.52	4.77	5.03	5.30	5.59	5.90	6.22
23	38	SCANA	Yes	No	9.3%	36.1%	####	(67.90)	2.54	2.65	2.77	2.90	3.03	3.31	3.57	3.81	4.02	4.24	4.47	4.72	4.98	5.25	5.53
				e					4.15	4.35	4.56	4.77	5.00	5.23	5.69	6.13	6.54	6.89	7.27	7.67	8.09	8.53	8.99
24	39	Sempra	Yes	No	10.4%	45.4%	####	(107.99)	3.51	3.75	4.00	4.28	4.56	5.07	5.54	5.95	6.28	6.62	6.98	7.36	7.77	8.19	8.64
				e					5.20	5.48	6.41	7.50	8.78	10.05	11.50	12.80	13.87	14.63	15.43	16.27	17.16	18.10	19.08
25	44	Vectren	Yes	No	8.9%	44.8%	####	(56.47)	1.78	1.85	1.92	2.00	2.08	2.26	2.44	2.60	2.74	2.89	3.05	3.22	3.39	3.58	3.77
				e					2.70	2.85	3.04	3.24	3.45	3.66	4.06	4.42	4.74	5.00	5.28	5.56	5.87	6.19	6.53
26	47	Xcel	Yes	No	9.5%	37.8%	####	(43.17)	1.52	1.61	1.70	1.80	1.90	2.10	2.28	2.44	2.57	2.71	2.86	3.01	3.18	3.35	3.54
				e					2.30	2.41	2.58	2.75	2.94	3.13	3.44	3.73	3.99	4.21	4.44	4.68	4.94	5.21	5.49

Abbreviated Utility	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41		
	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046 Terminal Value	2046 Div	2046 Sale	2047	#	
	Final Stage																			
AEP	5.87	6.19	6.53	6.89	7.26	7.66	8.08	8.52	8.98	9.48	9.99	10.54	11.11	11.72	381.10	12.36	368.74		1	1
	9.17	9.67	10.20	10.75	11.34	11.96	12.61	13.30	14.03	14.79	15.60	16.45	17.35	18.30		19.30		20.35		
Allete	4.92	5.18	5.47	5.77	6.08	6.41	6.76	7.13	7.52	7.93	8.37	8.82	9.30	9.81	349.46	10.35	339.11		2	2
	7.55	7.96	8.40	8.86	9.34	9.85	10.39	10.95	11.55	12.18	12.85	13.55	14.29	15.07		15.89		16.76		
Alliant	3.27	3.45	3.64	3.84	4.04	4.27	4.50	4.74	5.00	5.28	5.56	5.87	6.19	6.53	220.93	6.88	214.04		3	3
	4.94	5.21	5.49	5.79	6.11	6.44	6.80	7.17	7.56	7.97	8.41	8.87	9.35	9.86		10.40		10.97		
Ameren	4.32	4.56	4.81	5.07	5.35	5.64	5.95	6.27	6.62	6.98	7.36	7.76	8.18	8.63	301.38	9.10	292.28		4	4
	6.81	7.18	7.57	7.98	8.42	8.88	9.37	9.88	10.42	10.98	11.58	12.22	12.88	13.59		14.33		15.11		
CenterPoint	2.41	2.54	2.68	2.82	2.98	3.14	3.31	3.49	3.68	3.89	4.10	4.32	4.56	4.81	154.56	5.07	149.49		7	5
	3.23	3.40	3.59	3.79	3.99	4.21	4.44	4.68	4.94	5.21	5.49	5.79	6.11	6.44		6.79		7.16		
CMS	3.55	3.75	3.95	4.17	4.39	4.63	4.89	5.15	5.43	5.73	6.04	6.37	6.72	7.09	254.79	7.48	247.31		9	6
	5.45	5.74	6.06	6.39	6.74	7.10	7.49	7.90	8.33	8.79	9.27	9.77	10.31	10.87		11.46		12.09		
Consol Ed	5.92	6.24	6.58	6.94	7.32	7.72	8.14	8.59	9.06	9.55	10.07	10.62	11.20	11.82	371.91	12.46	359.45		10	7
	8.78	9.26	9.77	10.30	10.86	11.46	12.08	12.74	13.44	14.17	14.94	15.76	16.62	17.53		18.48		19.49		
Dominion	9.16	9.66	10.18	10.74	11.33	11.94	12.60	13.28	14.01	14.77	15.58	16.43	17.33	18.28	461.56	19.27	442.28		11	8
	8.78	9.25	9.76	10.29	10.85	11.45	12.07	12.73	13.43	14.16	14.93	15.75	16.61	17.51		18.47		19.48		
DTE	9.09	9.58	10.11	10.66	11.24	11.85	12.50	13.18	13.90	14.66	15.46	16.31	17.20	18.14	545.19	19.13	526.06		12	9
	12.49	13.17	13.89	14.64	15.44	16.29	17.18	18.11	19.10	20.15	21.25	22.41	23.63	24.92		26.28		27.71		
Edison Int'l	6.33	6.68	7.04	7.43	7.83	8.26	8.71	9.18	9.69	10.21	10.77	11.36	11.98	12.64	449.71	13.33	436.38		14	10
	10.53	11.10	11.71	12.35	13.02	13.74	14.49	15.28	16.11	16.99	17.92	18.90	19.93	21.02		22.16		23.37		
El Paso	3.82	4.03	4.25	4.48	4.73	4.98	5.26	5.54	5.85	6.17	6.50	6.86	7.23	7.63	227.37	8.04	219.33		15	11
	5.03	5.31	5.60	5.90	6.22	6.56	6.92	7.30	7.70	8.12	8.56	9.03	9.52	10.04		10.59		11.17		
Entergy	7.17	7.56	7.98	8.41	8.87	9.35	9.87	10.40	10.97	11.57	12.20	12.87	13.57	14.31	313.87	15.09	298.77		17	12
	8.72	9.20	9.70	10.23	10.79	11.38	12.00	12.66	13.35	14.08	14.84	15.66	16.51	17.41		18.36		19.36		
IDACORP	6.06	6.39	6.74	7.11	7.50	7.91	8.34	8.80	9.28	9.78	10.32	10.88	11.47	12.10	383.77	12.76	371.01		23	13
	8.25	8.70	9.17	9.67	10.20	10.76	11.35	11.97	12.62	13.31	14.03	14.80	15.61	16.46		17.36		18.31		
MGE	2.85	3.01	3.17	3.35	3.53	3.72	3.92	4.14	4.36	4.60	4.85	5.12	5.40	5.69	419.77	6.00	413.77		26	14
	6.66	7.02	7.40	7.81	8.23	8.68	9.16	9.66	10.18	10.74	11.33	11.94	12.60	13.28		14.01		14.77		
OGE	3.85	4.06	4.28	4.51	4.76	5.02	5.29	5.58	5.89	6.21	6.55	6.90	7.28	7.68	194.71	8.10	186.62		29	15
	4.89	5.16	5.44	5.73	6.05	6.38	6.72	7.09	7.48	7.89	8.32	8.77	9.25	9.76		10.29		10.85		
Otter Tail	2.60	2.74	2.89	3.05	3.21	3.39	3.57	3.77	3.98	4.19	4.42	4.66	4.92	5.19	223.90	5.47	218.44		30	16
	4.37	4.61	4.86	5.12	5.40	5.70	6.01	6.34	6.68	7.05	7.43	7.84	8.27	8.72		9.19		9.70		
PG&E	6.46	6.81	7.18	7.57	7.99	8.42	8.88	9.37	9.88	10.42	10.99	11.59	12.22	12.89	339.95	13.59	326.36		32	17
	8.24	8.69	9.17	9.67	10.20	10.75	11.34	11.96	12.61	13.30	14.03	14.80	15.60	16.46		17.35		18.30		
PGE	3.55	3.74	3.94	4.16	4.39	4.63	4.88	5.15	5.43	5.72	6.04	6.36	6.71	7.08	211.29	7.47	203.83		33	18
	4.74	5.00	5.27	5.56	5.86	6.18	6.52	6.88	7.25	7.65	8.07	8.51	8.97	9.46		9.98		10.52		
Pinnacle	6.59	6.95	7.33	7.73	8.16	8.60	9.07	9.57	10.09	10.64	11.22	11.83	12.48	13.16	396.64	13.88	382.76		34	19
	9.14	9.64	10.17	10.72	11.31	11.92	12.58	13.26	13.99	14.75	15.55	16.40	17.30	18.24		19.24		20.29		
PNM	3.23	3.41	3.60	3.79	4.00	4.22	4.45	4.69	4.95	5.22	5.50	5.81	6.12	6.46	236.71	6.81	229.90		35	20
	5.33	5.62	5.93	6.25	6.59	6.95	7.33	7.73	8.15	8.60	9.07	9.56	10.09	10.64		11.22		11.83		
PPL	3.55	3.74	3.94	4.16	4.39	4.62	4.88	5.14	5.42	5.72	6.03	6.36	6.71	7.08	193.34	7.46	185.88		36	21
	5.06	5.34	5.63	5.94	6.26	6.60	6.97	7.35	7.75	8.17	8.62	9.09	9.58	10.10		10.66		11.24		
Public Serv.	4.26	4.50	4.74	5.00	5.27	5.56	5.86	6.18	6.52	6.88	7.25	7.65	8.07	8.51	237.80	8.97	228.82		37	22
	6.56	6.92	7.29	7.69	8.11	8.56	9.02	9.52	10.04	10.58	11.16	11.77	12.41	13.09		13.81		14.56		
SCANA	5.84	6.16	6.49	6.85	7.22	7.61	8.03	8.47	8.93	9.42	9.93	10.47	11.05	11.65	356.78	12.29	344.49		38	23
	9.48	10.00	10.55	11.12	11.73	12.37	13.05	13.76	14.51	15.30	16.14	17.02	17.95	18.93		19.96		21.05		
Sempra	9.11	9.61	10.13	10.68	11.27	11.88	12.53	13.21	13.94	14.70	15.50	16.34	17.24	18.18	946.98	19.17	927.81		39	24
	20.13	21.23	22.38	23.61	24.90	26.26	27.69	29.20	30.79	32.48	34.25	36.12	38.09	40.17		42.36		44.68		
Vectren	3.98	4.19	4.42	4.67	4.92	5.19	5.47	5.77	6.09	6.42	6.77	7.14	7.53	7.94	327.93	8.37	319.56		44	25
	6.88	7.26	7.66	8.07	8.51	8.98	9.47	9.99	10.53	11.11	11.71	12.35	13.03	13.74		14.49		15.28		
Xcel	3.73	3.93	4.15	4.37	4.61	4.86	5.13	5.41	5.71	6.02	6.35	6.69	7.06	7.44	249.14	7.85	241.29		47	26
	5.79	6.11	6.44	6.79	7.16	7.56	7.97	8.40	8.86	9.35	9.86	10.39	10.96	11.56		12.19		12.86		

TOTALS	25	6	Mean		
w Sensitivities		3	9.22%	38.40%	0.00% Staff Peer Screen
			9.03%	39.36%	0.00% Staff Mid Cap Sensitivity
			9.35%	38.09%	0.00% Company Screen

Average B.O.Y. & E.O.Y. Cash Flows Model Y EPS Growth

	1	2	3	4	5	6	7	8	9		
	Screen #	Abbreviated Utility	UE 319 PGE	UE 319 Staff	Average IRR	Terminal Value as % of NPV_{DIV}	Average 2017 - 2021 Dividend Growth Rates EOY	BOY	Average	Screen #	
1	1	AEP	Yes	No	9.5%	37.5%	5.0%	4.9%	4.9%	1	1
2	2	Allete	Yes	No	8.7%	42.4%	4.0%	4.0%	4.0%	2	2
3	3	Alliant	Yes	No	9.3%	39.6%	5.8%	5.6%	5.7%	3	3
4	4	Ameren	Yes	Yes	9.1%	40.8%	4.8%	5.3%	5.0%	4	4
5	7	CenterPoint	Yes	No	9.6%	36.7%	3.5%	3.5%	3.5%	7	5
6	9	CMS	Yes	No	9.2%	41.5%	6.3%	6.1%	6.2%	9	6
7	10	Consol Ed	Yes	No	8.8%	39.0%	6.1%	2.7%	4.4%	10	7
8	11	Dominion	Yes	No	10.6%	28.7%	8.6%	8.2%	8.4%	11	8
9	12	DTE	Yes	No	9.4%	36.5%	6.4%	6.1%	6.2%	12	9
10	14	Edison Int'l	Yes	Yes	9.2%	41.7%	6.9%	6.8%	6.9%	14	10
11	15	El Paso	Yes	Yes	8.6%	39.3%	8.2%	8.0%	8.1%	15	11
12	17	Entergy	Yes	No	9.3%	28.7%	2.1%	2.0%	2.0%	17	12
13	23	IDACORP	Yes	Yes	8.4%	41.4%	6.5%	6.4%	6.4%	23	13
14	26	MGE	Yes	No	8.1%	62.6%	3.8%	3.7%	3.7%	26	14
15	29	OGE	Yes	No	10.1%	30.5%	8.3%	7.6%	8.0%	29	15
16	30	Otter Tail	Yes	No	8.9%	46.1%	1.9%	2.0%	1.9%	30	16
17	32	PG&E	Yes	Yes	9.6%	33.2%	9.1%	8.9%	9.0%	32	17
18	33	PGE	Yes	No	8.7%	38.8%	6.1%	-64.0%	-28.9%	33	18
19	34	Pinnacle	Yes	No	8.9%	38.1%	5.0%	4.9%	4.9%	34	19
20	35	PNM	No	Yes	9.7%	40.8%	10.2%	10.0%	10.1%	35	20
21	36	PPL	Yes	No	9.8%	32.2%	3.6%	3.5%	3.6%	36	21
22	37	Public Serv.	Yes	No	9.6%	33.7%	5.1%	5.2%	5.2%	37	22
23	38	SCANA	Yes	No	9.2%	37.1%	4.6%	4.5%	4.5%	38	23
24	39	Sempra	Yes	No	10.3%	46.5%	6.9%	6.8%	6.8%	39	24
25	44	Vectren	Yes	No	8.8%	45.7%	4.1%	3.9%	4.0%	44	25
26	47	Xcel	Yes	No	9.4%	38.8%	5.8%	5.7%	5.7%	47	26
		TOTALS	25	6	Mean						
		w Sensitivities		3	9.11%	39.51%	7.62%	Staff Peer Screen			
					8.92%	40.50%	8.28%	Staff Mid Cap Sensitivity			
					9.25%	39.81%	5.90%	Company Screen			

CASE: UE 319
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 504

Staff Synthetic Forward Curve TIPS Analysis

Exhibits in Support
of Opening Testimony

June 16, 2017

2028 through 2047 TIPs-Implied Average Annual Inflation Rate: 2.04%

Yr. End Mo.-Yr.	Years	Individually Implied Price Levels					Implied Forward Curve/Price Level					Implied Price Level	Check
		5-Yr	7-Yr	10-Yr	20-Yr	30-Yr	5-Yr	7-Yr	10-Yr	20-Yr	30-Yr		
Dec-17	0	100.00	100.00	100.00	100.00	100.00	100.00					100.00	
Dec-18	1	101.67	101.80	101.80	101.83	101.96	101.67					101.67	
Dec-19	2	103.37	103.64	103.64	103.69	103.96	103.37					103.37	
Dec-20	3	105.09	105.51	105.51	105.58	106.00	105.09					105.09	
Dec-21	4	106.85	107.41	107.41	107.51	108.07	106.85					106.85	
Dec-22	5	108.63	109.35	109.35	109.47	110.19	108.63					108.63	
Dec-23	6		111.32	111.32	111.47	112.35		110.96				110.96	
Dec-24	7		113.33	113.33	113.51	114.55		113.33				113.33	
Dec-25	8			115.37	115.58	116.80			115.37			115.37	
Dec-26	9			117.45	117.69	119.09			117.45			117.45	
Dec-27	10			119.57	119.84	121.42			119.57			119.57	
Dec-28	11				122.03	123.80				121.78		121.78	122.01
Dec-29	12				124.26	126.23				124.03		124.03	124.49
Dec-30	13				126.53	128.70				126.33		126.33	127.03
Dec-31	14				128.84	131.23				128.67		128.67	129.62
Dec-32	15				131.20	133.80				131.05		131.05	132.26
Dec-33	16				133.59	136.42				133.47		133.47	134.96
Dec-34	17				136.03	139.09				135.94		135.94	137.71
Dec-35	18				138.52	141.82				138.45		138.45	140.52
Dec-36	19				141.05	144.60				141.02		141.02	143.38
Dec-37	20				143.63	147.43				143.63		143.63	146.30
Dec-38	21					150.32					146.82	146.82	149.29
Dec-39	22					153.27					150.09	150.09	152.33
Dec-40	23					156.27					153.44	153.44	155.43
Dec-41	24					159.34					156.85	156.85	158.60
Dec-42	25					162.46					160.35	160.35	161.84
Dec-43	26					165.64					163.92	163.92	165.14
Dec-44	27					168.89					167.57	167.57	168.50
Dec-45	28					172.20					171.30	171.30	171.94
Dec-46	29					175.58					175.12	175.12	175.44
Dec-47	30					179.02					179.02	179.02	179.02

Average Quarterly Values for FRB H15 Data

See FRB H.15 Tab for Data Feed Sources.

Staff TIPS Analysis

Quarterly Aggregation

Average Monthly Inflation Indexed Rates by Quarter					
Qtr	TIPS-05m	TIPS-07m	TIPS-10m	TIPS-20m	TIPS-30m
2003-Q1	1.33	1.81	2.07		
2003-Q2	1.15	1.61	1.94		
2003-Q3	1.36	1.84	2.21		
2003-Q4	1.24	1.65	2.01		
2004-Q1	0.82	1.26	1.71		
2004-Q2	1.26	1.69	2.05		
2004-Q3	1.17	1.55	1.89	2.28	
2004-Q4	0.93	1.30	1.69	2.08	
2005-Q1	1.17	1.41	1.71	1.93	
2005-Q2	1.30	1.44	1.68	1.83	
2005-Q3	1.59	1.70	1.82	1.98	
2005-Q4	1.92	1.98	2.04	2.13	
2006-Q1	2.00	2.05	2.09	2.08	
2006-Q2	2.34	2.39	2.46	2.48	
2006-Q3	2.37	2.37	2.37	2.38	
2006-Q4	2.40	2.36	2.32	2.29	
2007-Q1	2.28	2.33	2.33	2.36	
2007-Q2	2.35	2.40	2.44	2.49	
2007-Q3	2.38	2.44	2.45	2.46	
2007-Q4	1.54	1.81	1.92	2.11	
2008-Q1	0.58	1.02	1.32	1.81	
2008-Q2	0.79	1.17	1.48	2.03	
2008-Q3	1.18	1.47	1.70	2.16	
2008-Q4	2.73	2.92	2.60	2.73	
2009-Q1	1.37	1.54	1.79	2.34	
2009-Q2	1.12	1.37	1.72	2.31	
2009-Q3	1.17	1.41	1.74	2.22	
2009-Q4	0.58	0.94	1.37	1.98	
2010-Q1	0.47	0.94	1.43	2.00	2.16
2010-Q2	0.46	0.91	1.36	1.77	1.88
2010-Q3	0.20	0.57	1.06	1.68	1.76
2010-Q4	-0.11	0.28	0.75	1.48	1.65
2011-Q1	0.07	0.67	1.09	1.71	2.00
2011-Q2	-0.29	0.33	0.80	1.49	1.78
2011-Q3	-0.65	-0.22	0.28	0.95	1.25
2011-Q4	-0.75	-0.39	0.05	0.61	0.85
2012-Q1	-1.02	-0.60	-0.17	0.51	0.78
2012-Q2	**-1.08**	**-0.75**	**-0.35**	**0.35**	**0.66**
2012-Q3	-1.27	-1.01	-0.63	0.02	0.43
2012-Q4	**-1.42**	**-1.15**	**-0.76**	**-0.02**	**0.36**
2013-Q1	-1.40	-0.98	-0.59	0.19	0.56
2013-Q2	**-1.04**	**-0.62**	**-0.25**	**0.47**	**0.80**
2013-Q3	-0.32	0.17	0.56	1.16	1.43
2013-Q4	**-0.29**	**0.25**	**0.57**	**1.19**	**1.50**
2014-Q1	-0.16	0.37	0.58	1.11	1.39
2014-Q2	**-0.25**	**0.27**	**0.43**	**0.88**	**1.14**
2014-Q3	-0.13	0.24	0.32	0.72	0.98
2014-Q4	**0.19**	**0.39**	**0.45**	**0.75**	**0.95**
2015-Q1	0.11	0.23	0.27	0.52	0.71
2015-Q2	**-0.10**	**0.22**	**0.30**	**0.67**	**0.91**
2015-Q3	0.26	0.48	0.57	0.92	1.14
2015-Q4	**0.36**	**0.51**	**0.66**	**1.02**	**1.24**
2016-Q1	0.15	0.32	0.49	0.88	1.11
2016-Q2	**-0.24**	**-0.05**	**0.19**	**0.62**	**0.85**
2016-Q3	-0.22	-0.09	0.08	0.44	0.62
2016-Q4	**-0.06**	**0.12**	**0.33**	**0.69**	**0.86**

Average Monthly Nominal UST Rates by Quarter					
Qtr	UST-05m	UST-07m	UST-10m	UST-20m	UST-30m
2003-Q1	2.91	3.46	3.92	4.90	
2003-Q2	2.57	3.13	3.62	4.59	
2003-Q3	3.14	3.72	4.23	5.17	
2003-Q4	3.25	3.78	4.29	5.16	
2004-Q1	2.99	3.52	4.02	4.89	
2004-Q2	3.72	4.18	4.60	5.36	
2004-Q3	3.51	3.92	4.30	5.07	
2004-Q4	3.49	3.85	4.17	4.87	
2005-Q1	3.88	4.09	4.30	4.76	
2005-Q2	3.87	3.99	4.16	4.55	
2005-Q3	4.04	4.11	4.21	4.51	
2005-Q4	4.39	4.42	4.49	4.77	
2006-Q1	4.55	4.55	4.57	4.76	4.64
2006-Q2	4.99	5.02	5.07	5.29	5.14
2006-Q3	4.84	4.85	4.90	5.09	4.99
2006-Q4	4.60	4.60	4.63	4.83	4.74
2007-Q1	4.65	4.65	4.68	4.90	4.80
2007-Q2	4.76	4.79	4.85	5.07	4.99
2007-Q3	4.50	4.60	4.73	5.01	4.94
2007-Q4	3.79	3.98	4.26	4.65	4.61
2008-Q1	2.75	3.15	3.66	4.40	4.41
2008-Q2	3.16	3.46	3.89	4.59	4.58
2008-Q3	3.11	3.44	3.86	4.49	4.45
2008-Q4	2.18	2.63	3.25	3.97	3.68
2009-Q1	1.76	2.23	2.74	3.69	3.45
2009-Q2	2.23	2.88	3.31	4.19	4.17
2009-Q3	2.47	3.12	3.52	4.28	4.32
2009-Q4	2.30	2.98	3.46	4.27	4.33
2010-Q1	2.42	3.16	3.72	4.49	4.62
2010-Q2	2.25	2.93	3.49	4.20	4.37
2010-Q3	1.55	2.19	2.79	3.60	3.85
2010-Q4	1.49	2.18	2.86	3.84	4.16
2011-Q1	2.12	2.83	3.46	4.32	4.56
2011-Q2	1.86	2.55	3.21	4.07	4.34
2011-Q3	1.15	1.78	2.43	3.34	3.70
2011-Q4	0.95	1.50	2.05	2.75	3.04
2012-Q1	0.90	1.44	2.04	2.80	3.14
2012-Q2	**0.79**	**1.24**	**1.82**	**2.55**	**2.94**
2012-Q3	0.67	1.08	1.64	2.37	2.75
2012-Q4	**0.69**	**1.12**	**1.71**	**2.46**	**2.86**
2013-Q1	0.83	1.32	1.95	2.75	3.14
2013-Q2	**0.92**	**1.39**	**2.00**	**2.78**	**3.15**
2013-Q3	1.51	2.12	2.71	3.44	3.72
2013-Q4	**1.44**	**2.12**	**2.75**	**3.50**	**3.79**
2014-Q1	1.60	2.22	2.76	3.42	3.68
2014-Q2	**1.66**	**2.19**	**2.62**	**3.18**	**2.86**
2014-Q3	1.70	2.16	2.50	3.01	3.26
2014-Q4	**1.60**	**2.00**	**2.28**	**2.69**	**2.97**
2015-Q1	1.45	1.77	1.97	2.32	2.55
2015-Q2	**1.52**	**1.91**	**2.17**	**2.62**	**2.89**
2015-Q3	1.55	1.94	2.22	2.65	2.96
2015-Q4	**1.59**	**1.94**	**2.19**	**2.60**	**2.96**
2016-Q1	1.37	1.69	1.92	2.32	2.72
2016-Q2	**1.24**	**1.54**	**1.75**	**2.15**	**2.57**
2016-Q3	1.13	1.40	1.56	1.91	2.28
2016-Q4	**1.61**	**1.93**	**2.13**	**2.52**	**2.82**

Implied Market-based Inflationary Expectations					
Qtr	5-Yr	7-Yr	10-Yr	20-Yr	30-Yr
2003-Q1	1.58	1.65	1.85		
2003-Q2	1.42	1.52	1.68		
2003-Q3	1.78	1.87	2.03		
2003-Q4	2.01	2.13	2.28		
2004-Q1	2.17	2.26	2.31		
2004-Q2	2.47	2.50	2.55		
2004-Q3	2.34	2.37	2.41	2.79	
2004-Q4	2.56	2.55	2.48	2.79	
2005-Q1	2.72	2.68	2.58	2.83	
2005-Q2	2.57	2.55	2.48	2.72	
2005-Q3	2.44	2.41	2.39	2.52	
2005-Q4	2.47	2.44	2.45	2.64	
2006-Q1	2.55	2.50	2.48	2.69	
2006-Q2	2.65	2.62	2.61	2.80	
2006-Q3	2.47	2.48	2.52	2.71	
2006-Q4	2.20	2.24	2.31	2.54	
2007-Q1	2.36	2.32	2.35	2.54	
2007-Q2	2.41	2.39	2.41	2.58	
2007-Q3	2.13	2.16	2.28	2.55	
2007-Q4	2.24	2.17	2.34	2.54	
2008-Q1	2.17	2.13	2.34	2.59	
2008-Q2	2.37	2.29	2.40	2.56	
2008-Q3	1.93	1.96	2.16	2.33	
2008-Q4	-0.55	-0.29	0.65	1.24	
2009-Q1	0.39	0.69	0.95	1.35	
2009-Q2	1.11	1.51	1.60	1.88	
2009-Q3	1.30	1.72	1.77	2.06	
2009-Q4	1.72	2.04	2.09	2.29	
2010-Q1	1.96	2.22	2.28	2.49	2.47
2010-Q2	1.80	2.03	2.13	2.43	2.49
2010-Q3	1.35	1.63	1.73	1.92	2.09
2010-Q4	1.59	1.90	2.12	2.36	2.51
2011-Q1	2.05	2.16	2.37	2.61	2.56
2011-Q2	2.15	2.22	2.41	2.57	2.56
2011-Q3	1.81	2.00	2.15	2.39	2.45
2011-Q4	1.71	1.89	1.99	2.14	2.19
2012-Q1	1.92	2.04	2.20	2.29	2.36
2012-Q2	**1.86**	**1.99**	**2.17**	**2.21**	**2.28**
2012-Q3	1.94	2.09	2.28	2.35	2.31
2012-Q4	**2.11**	**2.27**	**2.47**	**2.48**	**2.50**
2013-Q1	2.23	2.31	2.54	2.55	2.58
2013-Q2	**1.95**	**2.01**	**2.25**	**2.32**	**2.34**
2013-Q3	1.82	1.95	2.15	2.29	2.29
2013-Q4	**1.73**	**1.86**	**2.17**	**2.31**	**2.29**
2014-Q1	1.77	1.85	2.18	2.30	2.29
2014-Q2	**1.90**	**1.92**	**2.20**	**2.30**	**1.72**
2014-Q3	1.83	1.92	2.18	2.28	2.29
2014-Q4	**1.41**	**1.61**	**1.83**	**1.95**	**2.02**
2015-Q1	1.35	1.54	1.70	1.79	1.85
2015-Q2	**1.63**	**1.69**	**1.86**	**1.95**	**1.97**
2015-Q3	1.29	1.47	1.65	1.73	1.82
2015-Q4	**1.23**	**1.43**	**1.53**	**1.58**	**1.72**
2016-Q1	1.23	1.37	1.43	1.45	1.61
2016-Q2	**1.48**	**1.58**	**1.56**	**1.53**	**1.72**
2016-Q3	1.35	1.49	1.48	1.47	1.66
2016-Q4	**1.67**	**1.80**	**1.80**	**1.83**	**1.96**

Implied TIPS Expectations

Market-based Inflationary Expectations

FRB H.15 Market Yield on U.S. Treasury (UST) Securities at Constant Maturity, Quoted on an Investment Basis in Percent per Year

Staff Accessed , Jan. 6, 2017 at: http://federalreserve.gov/releases/h15/data.htm

https://www.federalreserve.gov/datadownload/Choose.aspx?rel=H15

Monthly

TIPS-05m	5	Year	Inflation Indexed	H.15 ID	RIFLGFCY05_XII_N.M
TIPS-07m	7				RIFLGFCY07_XII_N.M
TIPS-10m	10				RIFLGFCY10_XII_N.M
TIPS-20m	20				RIFLGFCY20_XII_N.M
TIPS-30m	30				RIFLGFCY30_XII_N.M

Month	TIPS-05m	TIPS-07m	TIPS-10m	TIPS-20m	TIPS-30m
2003-01	1.65	2.10	2.29		
2003-02	1.24	1.74	1.99		
2003-03	1.09	1.60	1.94		
2003-04	1.36	1.85	2.18		
2003-05	1.18	1.61	1.91		
2003-06	0.91	1.37	1.72		
2003-07	1.30	1.76	2.11		
2003-08	1.48	1.97	2.32		
2003-09	1.29	1.80	2.19		
2003-10	1.21	1.68	2.08		
2003-11	1.27	1.64	1.96		
2003-12	1.23	1.64	1.98		
2004-01	1.09	1.48	1.89		
2004-02	0.86	1.31	1.76		
2004-03	0.52	0.98	1.47		
2004-04	1.02	1.49	1.90		
2004-05	1.34	1.77	2.09		
2004-06	1.41	1.80	2.15	TIPS-20	
2004-07	1.29	1.68	2.02	2.44	
2004-08	1.12	1.51	1.86	2.23	
2004-09	1.10	1.46	1.80	2.16	
2004-10	0.97	1.35	1.73	2.13	
2004-11	0.90	1.27	1.68	2.09	
2004-12	0.92	1.28	1.67	2.02	
2005-01	1.13	1.40	1.72	1.98	
2005-02	1.08	1.33	1.63	1.85	
2005-03	1.29	1.49	1.79	1.95	
2005-04	1.23	1.42	1.71	1.87	
2005-05	1.28	1.41	1.65	1.82	
2005-06	1.39	1.49	1.67	1.80	
2005-07	1.67	1.75	1.88	2.00	
2005-08	1.71	1.79	1.89	2.02	
2005-09	1.40	1.56	1.70	1.93	
2005-10	1.70	1.82	1.94	2.09	
2005-11	1.97	2.03	2.06	2.16	
2005-12	2.09	2.10	2.12	2.14	
2006-01	1.93	1.98	2.01	2.05	
2006-02	1.98	2.02	2.05	2.01	
2006-03	2.09	2.15	2.20	2.17	
2006-04	2.26	2.34	2.41	2.43	
2006-05	2.30	2.36	2.45	2.48	
2006-06	2.45	2.48	2.53	2.54	
2006-07	2.46	2.48	2.51	2.52	
2006-08	2.27	2.29	2.29	2.31	
2006-09	2.38	2.35	2.32	2.31	
2006-10	2.51	2.45	2.41	2.38	
2006-11	2.41	2.35	2.29	2.23	
2006-12	2.28	2.28	2.25	2.26	
2007-01	2.47	2.47	2.44	2.42	
2007-02	2.34	2.38	2.36	2.38	
2007-03	2.04	2.14	2.18	2.27	
2007-04	2.12	2.20	2.26	2.35	
2007-05	2.29	2.32	2.37	2.45	
2007-06	2.65	2.67	2.69	2.67	
2007-07	2.60	2.63	2.64	2.62	
2007-08	2.39	2.45	2.44	2.47	
2007-09	2.14	2.24	2.26	2.30	
2007-10	2.01	2.15	2.20	2.26	
2007-11	1.35	1.65	1.77	1.99	
2007-12	1.27	1.62	1.79	2.08	
2008-01	0.86	1.24	1.47	1.81	
2008-02	0.65	1.09	1.41	1.87	
2008-03	0.23	0.73	1.09	1.76	
2008-04	0.62	1.00	1.36	1.91	
2008-05	0.79	1.16	1.46	2.00	
2008-06	0.97	1.35	1.63	2.19	
2008-07	0.84	1.24	1.57	2.09	
2008-08	1.15	1.47	1.68	2.15	
2008-09	1.55	1.71	1.85	2.25	
2008-10	2.75	2.96	2.75	2.87	
2008-11	3.69	3.84	2.89	3.00	
2008-12	1.76	1.96	2.17	2.32	
2009-01	1.59	1.72	1.91	2.46	
2009-02	1.29	1.48	1.75	2.31	
2009-03	1.23	1.43	1.71	2.26	
2009-04	1.11	1.29	1.57	2.22	
2009-05	1.07	1.34	1.72	2.36	
2009-06	1.18	1.48	1.86	2.36	
2009-07	1.18	1.44	1.82	2.31	
2009-08	1.29	1.49	1.77	2.22	
2009-09	1.03	1.29	1.64	2.13	
2009-10	0.83	1.12	1.48	2.04	
2009-11	0.48	0.84	1.28	1.90	
2009-12	0.43	0.86	1.36	1.99	
2010-01	0.42	0.85	1.37	2.00	TIPS-30
2010-02	0.42	0.90	1.42	2.03	2.16
2010-03	0.56	1.08	1.51	1.98	2.15
2010-04	0.62	1.10	1.50	1.90	2.05
2010-05	0.41	0.86	1.31	1.72	1.83
2010-06	0.34	0.76	1.26	1.69	1.77
2010-07	0.34	0.73	1.24	1.80	1.87
2010-08	0.13	0.51	1.02	1.65	1.76
2010-09	0.13	0.46	0.91	1.58	1.66
2010-10	-0.32	0.02	0.53	1.32	1.44
2010-11	-0.21	0.17	0.67	1.44	1.61
2010-12	0.21	0.65	1.04	1.67	1.89
2011-01	0.06	0.62	1.06	1.70	1.97
2011-02	0.25	0.84	1.24	1.85	2.13
2011-03	-0.09	0.54	0.96	1.58	1.89
2011-04	-0.14	0.49	0.86	1.48	1.79
2011-05	-0.34	0.29	0.78	1.47	1.77
2011-06	-0.38	0.21	0.76	1.53	1.78
2011-07	-0.49	0.09	0.62	1.36	1.62
2011-08	-0.75	-0.36	0.14	0.81	1.10
2011-09	-0.72	-0.39	0.08	0.69	1.02
2011-10	-0.63	-0.28	0.19	0.72	0.99
2011-11	-0.85	-0.46	0.00	0.55	0.78
2011-12	-0.78	-0.44	-0.03	0.56	0.78
2012-01	-0.92	-0.55	-0.11	0.51	0.74
2012-02	-1.11	-0.69	-0.25	0.45	0.72
2012-03	-1.03	-0.57	-0.14	0.56	0.87
2012-04	-1.06	-0.65	-0.21	0.50	0.79
2012-05	-1.12	-0.79	-0.34	0.44	0.68
2012-06	-1.05	-0.82	-0.50	0.10	0.50
2012-07	-1.15	-0.92	-0.60	-0.01	0.39
2012-08	-1.19	-0.94	-0.59	0.06	0.47
2012-09	-1.47	-1.17	-0.71	0.02	0.44
2012-10	-1.47	-1.18	-0.75	-0.01	0.41
2012-11	-1.38	-1.13	-0.77	-0.06	0.35
2012-12	-1.40	-1.13	-0.76	0.00	0.33
2013-01	-1.39	-1.04	-0.61	0.20	0.48
2013-02	-1.39	-0.94	-0.57	0.19	0.57
2013-03	-1.43	-0.97	-0.59	0.19	0.62
2013-04	-1.38	-0.97	-0.65	0.07	0.48
2013-05	-1.14	-0.69	-0.36	0.35	0.72
2013-06	-0.59	-0.21	0.25	0.98	1.21
2013-07	-0.45	0.02	0.46	1.09	1.34
2013-08	-0.33	0.15	0.55	1.16	1.44
2013-09	-0.17	0.34	0.66	1.22	1.50
2013-10	-0.41	0.11	0.43	1.05	1.37
2013-11	-0.38	0.18	0.55	1.20	1.51
2013-12	-0.09	0.47	0.74	1.32	1.61
2014-01	-0.09	0.45	0.63	1.17	1.44
2014-02	-0.26	0.30	0.55	1.12	1.40
2014-03	-0.14	0.37	0.56	1.05	1.33
2014-04	-0.11	0.38	0.54	0.98	1.23
2014-05	-0.34	0.21	0.37	0.82	1.08
2014-06	-0.29	0.23	0.37	0.84	1.11
2014-07	-0.27	0.18	0.28	0.72	0.98
2014-08	-0.21	0.15	0.22	0.64	0.90
2014-09	0.10	0.38	0.46	0.81	1.05
2014-10	0.06	0.32	0.38	0.74	0.96
2014-11	0.14	0.37	0.45	0.77	0.99
2014-12	0.37	0.47	0.51	0.73	0.89
2015-01	0.17	0.24	0.27	0.50	0.66
2015-02	0.11	0.22	0.26	0.52	0.73
2015-03	0.04	0.23	0.28	0.55	0.73
2015-04	-0.26	-0.01	0.08	0.42	0.65
2015-05	-0.10	0.27	0.33	0.70	0.96
2015-06	0.05	0.39	0.50	0.89	1.13
2015-07	0.14	0.42	0.50	0.87	1.11
2015-08	0.31	0.49	0.56	0.87	1.08
2015-09	0.33	0.52	0.65	1.01	1.24
2015-10	0.21	0.39	0.57	0.98	1.22
2015-11	0.40	0.55	0.69	1.03	1.25
2015-12	0.46	0.59	0.73	1.06	1.26
2016-01	0.33	0.49	0.67	1.05	1.26
2016-02	0.14	0.30	0.47	0.85	1.09
2016-03	-0.03	0.16	0.34	0.73	0.99
2016-04	-0.22	-0.03	0.19	0.60	0.86
2016-05	-0.22	-0.04	0.21	0.64	0.86
2016-06	-0.27	-0.07	0.17	0.63	0.82
2016-07	-0.32	-0.16	0.04	0.42	0.61
2016-08	-0.17	-0.06	0.09	0.43	0.62
2016-09	-0.17	-0.05	0.12	0.47	0.64
2016-10	-0.26	-0.10	0.10	0.49	0.69
2016-11	-0.07	0.11	0.32	0.69	0.86
2016-12	0.15	0.36	0.56	0.89	1.04

Monthly

UST-05m	5	Year	H.15 ID	RIFLGFCY05_N.M
UST-07m	7			RIFLGFCY07_N.M
UST-10m	10			RIFLGFCY10_N.M
UST-20m	20			RIFLGFCY20_N.M
UST-30m	30			RIFLGFCY30_N.M

Month	UST-05m	UST-07m	UST-10m	UST-20m	UST-30m
2003-01	3.05	3.60	4.05	5.02	
2003-02	2.90	3.45	3.90	4.87	
2003-03	2.78	3.34	3.81	4.82	
2003-04	2.93	3.47	3.96	4.91	
2003-05	2.52	3.07	3.57	4.52	
2003-06	2.27	2.84	3.33	4.34	
2003-07	2.87	3.45	3.98	4.92	
2003-08	3.37	3.96	4.45	5.39	
2003-09	3.18	3.74	4.27	5.21	
2003-10	3.19	3.75	4.29	5.21	
2003-11	3.29	3.81	4.30	5.17	
2003-12	3.27	3.79	4.27	5.11	
2004-01	3.12	3.65	4.15	5.01	
2004-02	3.07	3.59	4.08	4.94	
2004-03	2.79	3.31	3.83	4.72	
2004-04	3.39	3.89	4.35	5.16	
2004-05	3.85	4.31	4.72	5.46	
2004-06	3.93	4.35	4.73	5.45	
2004-07	3.69	4.11	4.50	5.24	
2004-08	3.47	3.90	4.28	5.07	
2004-09	3.36	3.75	4.13	4.89	
2004-10	3.35	3.75	4.10	4.85	
2004-11	3.53	3.88	4.19	4.89	
2004-12	3.60	3.93	4.23	4.88	
2005-01	3.71	3.97	4.22	4.77	
2005-02	3.77	3.97	4.17	4.61	
2005-03	4.17	4.33	4.50	4.89	
2005-04	4.00	4.16	4.34	4.75	
2005-05	3.85	3.94	4.14	4.56	
2005-06	3.77	3.86	4.00	4.35	
2005-07	3.98	4.06	4.18	4.48	
2005-08	4.12	4.18	4.26	4.53	
2005-09	4.01	4.08	4.20	4.51	
2005-10	4.33	4.38	4.46	4.74	
2005-11	4.45	4.48	4.54	4.83	
2005-12	4.39	4.41	4.47	4.73	
2006-01	4.35	4.37	4.42	4.65	UST-30
2006-02	4.57	4.56	4.57	4.73	4.54
2006-03	4.72	4.71	4.72	4.91	4.73
2006-04	4.90	4.94	4.99	5.22	5.06
2006-05	5.00	5.03	5.11	5.35	5.20
2006-06	5.07	5.08	5.11	5.29	5.15
2006-07	5.04	5.05	5.09	5.25	5.13
2006-08	4.82	4.83	4.88	5.08	5.00
2006-09	4.67	4.68	4.72	4.93	4.85
2006-10	4.69	4.69	4.73	4.94	4.85
2006-11	4.58	4.58	4.60	4.78	4.69
2006-12	4.53	4.54	4.56	4.78	4.68
2007-01	4.75	4.75	4.76	4.95	4.85
2007-02	4.71	4.71	4.72	4.93	4.82
2007-03	4.48	4.50	4.56	4.81	4.72
2007-04	4.59	4.62	4.69	4.95	4.87
2007-05	4.67	4.69	4.75	4.98	4.90
2007-06	5.03	5.05	5.10	5.29	5.20
2007-07	4.88	4.93	5.00	5.19	5.11
2007-08	4.43	4.53	4.67	5.00	4.93
2007-09	4.20	4.33	4.52	4.84	4.79
2007-10	4.20	4.33	4.53	4.83	4.77
2007-11	3.67	3.87	4.15	4.56	4.52
2007-12	3.49	3.74	4.10	4.57	4.53
2008-01	2.98	3.31	3.74	4.35	4.33
2008-02	2.78	3.21	3.74	4.49	4.52
2008-03	2.48	2.93	3.51	4.36	4.39
2008-04	2.84	3.19	3.68	4.44	4.44
2008-05	3.15	3.46	3.88	4.60	4.60
2008-06	3.49	3.73	4.10	4.74	4.69
2008-07	3.30	3.60	4.01	4.62	4.57
2008-08	3.14	3.46	3.89	4.53	4.50
2008-09	2.88	3.25	3.69	4.32	4.27
2008-10	2.73	3.19	3.81	4.45	4.17
2008-11	2.29	2.82	3.53	4.27	4.00
2008-12	1.52	1.89	2.42	3.18	2.87
2009-01	1.60	1.98	2.52	3.46	3.13
2009-02	1.87	2.30	2.87	3.83	3.59
2009-03	1.82	2.42	2.82	3.78	3.64
2009-04	1.86	2.47	2.93	3.84	3.76
2009-05	2.13	2.81	3.29	4.22	4.23
2009-06	2.71	3.37	3.72	4.51	4.52
2009-07	2.46	3.14	3.56	4.38	4.41
2009-08	2.57	3.21	3.59	4.33	4.37
2009-09	2.37	3.02	3.40	4.14	4.19
2009-10	2.33	2.96	3.39	4.16	4.19
2009-11	2.23	2.92	3.40	4.24	4.31
2009-12	2.34	3.07	3.59	4.40	4.49
2010-01	2.48	3.21	3.73	4.50	4.60
2010-02	2.36	3.12	3.69	4.48	4.62
2010-03	2.43	3.16	3.73	4.49	4.64
2010-04	2.58	3.28	3.85	4.53	4.69
2010-05	2.18	2.86	3.42	4.11	4.29
2010-06	2.00	2.66	3.20	3.95	4.13
2010-07	1.76	2.43	3.01	3.80	3.99
2010-08	1.47	2.10	2.70	3.52	3.80
2010-09	1.41	2.05	2.65	3.47	3.77
2010-10	1.18	1.85	2.54	3.52	3.87
2010-11	1.35	2.02	2.76	3.82	4.19
2010-12	1.93	2.66	3.29	4.17	4.42
2011-01	1.99	2.72	3.39	4.28	4.52
2011-02	2.26	2.96	3.58	4.42	4.65
2011-03	2.11	2.80	3.41	4.27	4.51
2011-04	2.17	2.84	3.46	4.28	4.50
2011-05	1.84	2.51	3.17	4.01	4.29
2011-06	1.58	2.29	3.00	3.91	4.23
2011-07	1.54	2.28	3.00	3.95	4.27
2011-08	1.02	1.63	2.30	3.24	3.65
2011-09	0.90	1.42	1.98	2.83	3.18
2011-10	1.06	1.62	2.15	2.87	3.13
2011-11	0.91	1.45	2.01	2.72	3.02
2011-12	0.89	1.43	1.98	2.67	2.98
2012-01	0.84	1.38	1.97	2.70	3.03
2012-02	0.83	1.37	1.97	2.75	3.11
2012-03	1.02	1.56	2.17	2.94	3.28
2012-04	0.89	1.43	2.05	2.82	3.18
2012-05	0.76	1.21	1.80	2.53	2.93
2012-06	0.71	1.08	1.62	2.31	2.70
2012-07	0.62	0.98	1.53	2.22	2.59
2012-08	0.71	1.14	1.68	2.40	2.77
2012-09	0.67	1.12	1.72	2.49	2.88
2012-10	0.71	1.15	1.75	2.51	2.90
2012-11	0.67	1.08	1.65	2.39	2.80
2012-12	0.70	1.13	1.72	2.47	2.88
2013-01	0.81	1.30	1.91	2.68	3.08
2013-02	0.85	1.35	1.98	2.78	3.17
2013-03	0.82	1.32	1.96	2.78	3.16
2013-04	0.71	1.15	1.76	2.55	2.93
2013-05	0.84	1.31	1.93	2.73	3.11
2013-06	1.20	1.71	2.30	3.07	3.40
2013-07	1.40	1.99	2.58	3.31	3.61
2013-08	1.52	2.15	2.74	3.49	3.76
2013-09	1.60	2.22	2.81	3.53	3.79
2013-10	1.37	1.99	2.62	3.38	3.68
2013-11	1.37	2.07	2.72	3.50	3.80
2013-12	1.58	2.29	2.90	3.63	3.89
2014-01	1.65	2.29	2.86	3.52	3.77
2014-02	1.52	2.15	2.71	3.38	3.66
2014-03	1.64	2.23	2.72	3.35	3.62
2014-04	1.70	2.27	2.71	3.27	3.52
2014-05	1.59	2.12	2.56	3.12	3.39
2014-06	1.68	2.19	2.60	3.15	3.42
2014-07	1.70	2.17	2.54	3.07	3.33
2014-08	1.63	2.08	2.42	2.94	3.20
2014-09	1.77	2.22	2.53	3.01	3.26
2014-10	1.55	1.98	2.30	2.77	3.04
2014-11	1.62	2.03	2.33	2.76	3.04
2014-12	1.64	1.98	2.21	2.55	2.83
2015-01	1.37	1.67	1.88	2.20	2.46
2015-02	1.47	1.79	1.98	2.34	2.57
2015-03	1.52	1.84	2.04	2.41	2.63
2015-04	1.35	1.69	1.94	2.33	2.59
2015-05	1.54	1.93	2.20	2.69	2.96
2015-06	1.68	2.10	2.36	2.85	3.11
2015-07	1.63	2.04	2.32	2.77	3.07
2015-08	1.54	1.91	2.17	2.55	2.86
2015-09	1.49	1.88	2.17	2.62	2.95
2015-10	1.39	1.76	2.07	2.50	2.89
2015-11	1.67	2.02	2.26	2.69	3.03
2015-12	1.70	2.04	2.24	2.61	2.97
2016-01	1.52	1.85	2.09	2.49	2.86
2016-02	1.22	1.53	1.78	2.20	2.62
2016-03	1.38	1.68	1.89	2.28	2.68
2016-04	1.26	1.57	1.81	2.21	2.62
2016-05	1.30	1.60	1.81	2.22	2.63
2016-06	1.17	1.44	1.64	2.02	2.45
2016-07	1.07	1.33	1.50	1.82	2.23
2016-08	1.13	1.40	1.56	1.89	2.26
2016-09	1.18	1.46	1.63	2.02	2.35
2016-10	1.27	1.56	1.76	2.17	2.50
2016-11	1.60	1.93	2.14	2.54	2.86
2016-12	1.96	2.29	2.49	2.84	3.11

Staff Accessed , Jan. 6, 2017 at: http://federalreserve.gov/releases/h15/data.htm

https://www.federalreserve.gov/datadownload/Choose.aspx?rel=H15

Annual

TIPS-05a	5	Year	Inflation Indexed	H.15 ID	RIFLGFCY05_XII_N.A
TIPS-07a	7				RIFLGFCY07_XII_N.A
TIPS-10a	10				RIFLGFCY10_XII_N.A
TIPS-20a	20				RIFLGFCY20_XII_N.A
TIPS-30a	30				RIFLGFCY30_XII_N.A

Year	TIPS-05a	TIPS-07a	TIPS-10a	TIPS-20a	TIPS-30a
2003	1.27	1.73	2.06		
2004	1.04	1.45	1.83	2.14	
2005	1.50	1.63	1.81	1.97	
2006	2.28	2.29	2.31	2.31	
2007	2.15	2.25	2.29	2.36	
2008	1.30	1.63	1.77	2.18	
2009	1.06	1.32	1.66	2.21	
2010	0.26	0.68	1.15	1.73	1.82
2011	-0.41	0.09	0.55	1.19	1.47
2012	-1.19	-0.87	-0.48	0.22	0.56
2013	0.76	-0.29	0.07	0.75	1.07
2014	-0.09	0.32	0.44	0.86	1.11
2015	0.15	0.36	0.45	0.78	1.00
2016	-0.01	0.07	0.27	0.65	0.86

AVA UG 305

AVA UG 325

Annual

UST-05a	5	Year	H.15 ID	RIFLGFCY05_N.A
UST-07a	7			RIFLGFCY07_N.A
UST-10a	10			RIFLGFCY10_N.A
UST-20a	20			RIFLGFCY20_N.A
UST-30a	30			RIFLGFCY30_N.A

Year	UST-05a	UST-07a	UST-10a	UST-20a	UST-30a
2003	2.97	3.52	4.01	4.96	
2004	3.43	3.87	4.27	5.04	
2005	4.05	4.15	4.29	4.64	
2006	4.75	4.76	4.80	5.00	4.91
2007	4.43	4.51	4.63	4.91	4.84
2008	2.80	3.17	3.66	4.36	4.28
2009	2.20	2.82	3.26	4.11	4.08
2010	1.93	2.62	3.22	4.03	4.25
2011	1.52	2.16	2.78	3.62	3.91
2012	0.76	1.22	1.80	2.54	2.92
2013	1.17	1.74	2.35	3.12	3.45
2014	1.64	2.14	2.54	3.07	3.34
2015	1.53	1.89	2.14	2.55	2.84
2016	1.33	1.63	1.84	2.22	2.59

CASE: UE 319
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 505

Staff Historical GDP Analysis with BEA Data

Exhibits in Support
of Opening Testimony

June 16, 2017

Bureau of Economic Analysis (BEA)

Staff Accessed January 6, 2017

Current-Dollar and "Real" Gross Domestic Product (GDP)

Annual

http://www.bea.gov/national/index.htm

Yr	GDP in billions of current dollars	GDP in billions of chained 2009 dollars
1929	104.6	1,056.6
1930	92.2	966.7
1931	77.4	904.8
1932	59.5	788.2
1933	57.2	778.3
1934	66.8	862.2
1935	74.3	939.0
1936	84.9	1,060.5
1937	93.0	1,114.6
1938	87.4	1,077.7
1939	93.5	1,163.6
1940	102.9	1,266.1
1941	129.4	1,490.3
1942	166.0	1,771.8
1943	203.1	2,073.7
1944	224.6	2,239.4
1945	228.2	2,217.8
1946	227.8	1,960.9
1947	249.9	1,939.4
1948	274.8	2,020.0
1949	272.8	2,008.9
1950	300.2	2,184.0
1951	347.3	2,360.0
1952	367.7	2,456.1
1953	389.7	2,571.4
1954	391.1	2,556.9
1955	426.2	2,739.0
1956	450.1	2,797.4
1957	474.9	2,856.3
1958	482.0	2,835.3
1959	522.5	3,031.0
1960	543.3	3,108.7
1961	563.3	3,188.1
1962	605.1	3,383.1
1963	638.6	3,530.4
1964	685.8	3,734.0
1965	743.7	3,976.7
1966	815.0	4,238.9
1967	861.7	4,355.2
1968	942.5	4,569.0
1969	1,019.9	4,712.5
1970	1,075.9	4,722.0
1971	1,167.8	4,877.6
1972	1,282.4	5,134.3
1973	1,428.5	5,424.1
1974	1,548.8	5,396.0
1975	1,688.9	5,385.4
1976	1,877.6	5,675.4
1977	2,086.0	5,937.0
1978	2,356.6	6,267.2
1979	2,632.1	6,466.2
1980	2,862.5	6,450.4
1981	3,211.0	6,617.7
1982	3,345.0	6,491.3
1983	3,638.1	6,792.0
1984	4,040.7	7,285.0
1985	4,346.7	7,593.8
1986	4,590.2	7,860.5
1987	4,870.2	8,132.6
1988	5,252.6	8,474.5
1989	5,657.7	8,786.4
1990	5,979.6	8,955.0
1991	6,174.0	8,948.4
1992	6,539.3	9,266.6
1993	6,878.7	9,521.0
1994	7,308.8	9,905.4
1995	7,664.1	10,174.8
1996	8,100.2	10,561.0
1997	8,608.5	11,034.9
1998	9,089.2	11,525.9
1999	9,660.6	12,065.9
2000	10,284.8	12,559.7
2001	10,621.8	12,682.2
2002	10,977.5	12,908.8
2003	11,510.7	13,271.1
2004	12,274.9	13,773.5
2005	13,093.7	14,234.2
2006	13,855.9	14,613.8
2007	14,477.6	14,873.7
2008	14,718.6	14,830.4
2009	14,418.7	14,418.7
2010	14,964.4	14,783.8
2011	15,517.9	15,020.6
2012	16,155.3	15,354.6
2013	16,691.5	15,612.2
2014	17,393.1	15,982.3
2015	18,036.6	16,397.2

Quarterly

(Seasonally adjusted annual rates)

Quarter	GDP in billions of current dollars	GDP in billions of chained 2009 dollars	Qtr#
1947q1	243.1	1,934.5	1
1947q2	246.3	1,932.3	2
1947q3	250.1	1,930.3	3
1947q4	260.3	1,960.7	4
1948q1	266.2	1,989.5	5
1948q2	272.9	2,021.9	6
1948q3	279.5	2,033.2	7
1948q4	280.7	2,035.3	8
1949q1	275.4	2,007.5	9
1949q2	271.7	2,000.8	10
1949q3	273.3	2,022.8	11
1949q4	271.0	2,004.7	12
1950q1	281.2	2,084.6	13
1950q2	290.7	2,147.6	14
1950q3	308.5	2,230.4	15
1950q4	320.3	2,273.4	16
1951q1	336.4	2,304.5	17
1951q2	344.5	2,344.5	18
1951q3	351.8	2,392.8	19
1951q4	356.6	2,398.1	20
1952q1	360.2	2,423.5	21
1952q2	361.4	2,428.5	22
1952q3	368.1	2,446.1	23
1952q4	381.2	2,526.4	24
1953q1	388.5	2,573.4	25
1953q2	392.3	2,593.5	26
1953q3	391.7	2,578.9	27
1953q4	386.5	2,539.8	28
1954q1	385.9	2,528.0	29
1954q2	386.7	2,530.7	30
1954q3	391.6	2,559.4	31
1954q4	400.3	2,609.3	32
1955q1	413.8	2,683.8	33
1955q2	422.2	2,727.5	34
1955q3	430.9	2,764.1	35
1955q4	437.8	2,780.8	36
1956q1	440.5	2,770.0	37
1956q2	446.8	2,792.9	38
1956q3	452.0	2,790.6	39
1956q4	461.3	2,836.2	40
1957q1	470.6	2,854.5	41
1957q2	472.8	2,848.2	42
1957q3	480.3	2,875.9	43
1957q4	475.7	2,846.4	44
1958q1	468.4	2,772.7	45
1958q2	472.8	2,790.9	46
1958q3	486.7	2,855.5	47
1958q4	500.4	2,922.3	48
1959q1	511.1	2,976.6	49
1959q2	524.2	3,049.0	50
1959q3	525.2	3,043.1	51
1959q4	529.3	3,055.1	52
1960q1	543.3	3,123.2	53
1960q2	542.7	3,111.3	54
1960q3	546.0	3,119.1	55
1960q4	541.1	3,081.3	56
1961q1	545.9	3,102.3	57
1961q2	557.4	3,159.9	58
1961q3	568.2	3,212.6	59
1961q4	581.6	3,277.7	60
1962q1	595.2	3,336.8	61
1962q2	602.6	3,372.7	62
1962q3	609.6	3,404.8	63
1962q4	613.1	3,418.0	64
1963q1	622.7	3,456.1	65
1963q2	631.8	3,501.1	66
1963q3	645.0	3,569.5	67
1963q4	654.8	3,595.0	68
1964q1	671.1	3,672.7	69
1964q2	680.8	3,716.4	70
1964q3	692.8	3,766.9	71
1964q4	698.4	3,780.2	72
1965q1	719.2	3,873.5	73
1965q2	732.4	3,926.4	74
1965q3	750.2	4,006.2	75
1965q4	773.1	4,100.6	76
1966q1	797.3	4,201.9	77
1966q2	807.2	4,219.1	78
1966q3	820.8	4,249.2	79
1966q4	834.9	4,285.6	80
1967q1	846.0	4,324.9	81
1967q2	851.1	4,328.7	82
1967q3	866.6	4,366.1	83
1967q4	883.2	4,401.2	84
1968q1	911.1	4,490.6	85
1968q2	936.3	4,566.4	86
1968q3	952.3	4,599.3	87
1968q4	970.1	4,619.8	88
1969q1	995.4	4,691.6	89
1969q2	1,011.4	4,706.7	90
1969q3	1,032.0	4,736.1	91
1969q4	1,040.7	4,715.5	92
1970q1	1,053.5	4,707.1	93
1970q2	1,070.1	4,715.4	94
1970q3	1,088.5	4,757.2	95
1970q4	1,091.5	4,708.3	96
1971q1	1,137.8	4,834.3	97
1971q2	1,159.4	4,861.9	98
1971q3	1,180.3	4,900.0	99
1971q4	1,193.6	4,914.3	100
1972q1	1,233.8	5,002.4	101
1972q2	1,270.1	5,118.3	102
1972q3	1,293.8	5,165.4	103
1972q4	1,332.0	5,251.2	104
1973q1	1,380.7	5,380.5	105
1973q2	1,417.6	5,441.5	106
1973q3	1,436.8	5,411.9	107
1973q4	1,479.1	5,462.4	108
1974q1	1,494.7	5,417.0	109
1974q2	1,534.2	5,431.3	110
1974q3	1,563.4	5,378.7	111
1974q4	1,603.0	5,357.2	112
1975q1	1,619.6	5,292.4	113
1975q2	1,656.4	5,333.2	114
1975q3	1,713.8	5,421.4	115
1975q4	1,765.9	5,494.4	116
1976q1	1,824.5	5,618.5	117
1976q2	1,856.9	5,661.0	118
1976q3	1,890.5	5,689.8	119
1976q4	1,938.4	5,732.5	120
1977q1	1,992.5	5,799.2	121
1977q2	2,060.2	5,913.0	122
1977q3	2,122.4	6,017.6	123
1977q4	2,168.7	6,018.2	124
1978q1	2,208.7	6,039.2	125
1978q2	2,336.6	6,274.0	126
1978q3	2,398.9	6,335.3	127
1978q4	2,482.2	6,420.3	128
1979q1	2,531.6	6,433.0	129
1979q2	2,595.9	6,440.8	130
1979q3	2,670.4	6,487.1	131
1979q4	2,730.7	6,503.9	132
1980q1	2,796.5	6,524.9	133
1980q2	2,799.9	6,392.6	134
1980q3	2,860.0	6,382.9	135
1980q4	2,993.5	6,501.2	136
1981q1	3,131.8	6,635.7	137
1981q2	3,167.3	6,587.3	138
1981q3	3,261.2	6,662.9	139
1981q4	3,283.5	6,585.1	140
1982q1	3,273.8	6,475.0	141
1982q2	3,331.3	6,510.2	142
1982q3	3,367.1	6,486.8	143
1982q4	3,407.8	6,493.1	144
1983q1	3,480.3	6,578.2	145
1983q2	3,583.8	6,728.3	146
1983q3	3,692.3	6,860.0	147
1983q4	3,796.1	7,001.5	148

1980 through 2016 Q3

Average	5.46%	Nominal
Average	2.63%	Real
1	8.783381	1980
2	8.762896	
3	8.761378	
4	8.779742	
5	8.800219	1981
6	8.792899	
7	8.804310	
8	8.792565	
9	8.775704	1982
10	8.781125	
11	8.777525	
12	8.778495	
13	8.791516	1983
14	8.814078	
15	8.833463	
16	8.853880	
17	8.873552	1984
18	8.890961	
19	8.900753	
20	8.908695	
21	8.918583	1985
22	8.927699	
23	8.943140	
24	8.950611	
25	8.959838	1986
26	8.964414	
27	8.974441	
28	8.979606	
29	8.986572	1987
30	8.997729	
31	9.006754	
32	9.023131	
33	9.028735	1988
34	9.041863	
35	9.047621	
36	9.060784	
37	9.070814	1989
38	9.078647	
39	9.086080	
40	9.088195	
41	9.099085	1990
42	9.102944	
43	9.103189	
44	9.094638	
45	9.089934	1991
46	9.097664	
47	9.102454	
48	9.106800	
49	9.118554	1992
50	9.129510	
51	9.139188	
52	9.149156	
53	9.151026	1993
54	9.156950	
55	9.161812	
56	9.175076	
57	9.184838	1994
58	9.198409	
59	9.204292	
60	9.215577	
61	9.218993	1995
62	9.222476	
63	9.231005	
64	9.238072	
65	9.244616	1996
66	9.261927	
67	9.271134	
68	9.281647	
69	9.289235	1997
70	9.304213	
71	9.316860	
72	9.324588	
73	9.334432	1998
74	9.344084	
75	9.357087	
76	9.373369	
77	9.381323	1999
78	9.389532	
79	9.402043	
80	9.419247	
81	9.422148	2000
82	9.440857	
83	9.442063	
84	9.447726	
85	9.444883	2001
86	9.450168	
87	9.447000	
88	9.449775	
89	9.458941	2002
90	9.464440	
91	9.469299	
92	9.469932	
93	9.475102	2003
94	9.484337	
95	9.500948	
96	9.512569	
97	9.518303	2004
98	9.525604	
99	9.534653	
100	9.543263	
101	9.553866	2005
102	9.559073	
103	9.567441	
104	9.573135	
105	9.585078	2006
106	9.588064	
107	9.588955	
108	9.596752	
109	9.597370	2007
110	9.604994	
111	9.611697	
112	9.615259	
113	9.608412	2008
114	9.613362	
115	9.608553	
116	9.587200	
117	9.573246	2009
118	9.571895	
119	9.575157	
120	9.584789	
121	9.589106	2010
122	9.598720	
123	9.605452	
124	9.611731	
125	9.607861	2011
126	9.615112	
127	9.617211	
128	9.628412	
129	9.635020	2012
130	9.639678	
131	9.640875	
132	9.641103	
133	9.648073	2013
134	9.649988	
135	9.657670	
136	9.667379	
137	9.664405	2014
138	9.674125	
139	9.686233	
140	9.691945	
141	9.697017	2015
142	9.703462	
143	9.708379	
144	9.710552	
145	9.712630	2016
146	9.716139	
147	9.724779	

OLS Regression

Annualized Real LN GPD Q

2.80%

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.987369563
R Square	0.974898655
Adjusted R Square	0.974725542
Standard Error	0.047411547
Observations	147

ANOVA

	df	SS	MS	F	Significance F
Regression	1	12.65898051	12.65898051	5631.582812	6.3677E-118
Residual	145	0.325938947	0.002247855		
Total	146	12.98491946			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	8.790216674	0.00786095	1118.213012	3.02E-287	8.774679824	8.805753524	8.774679824	8.805753524
X Variable 1	0.006915507	9.21529E-05	75.04387258	6.3677E-118	0.006733371	0.007097644	0.006733371	0.007097644

GDP is an array of expenditure and income data collected by BEA directly and through other government agencies.

www.bea.gov

Note July 31, 2013, 14th Comprehensive Significant Revision:
BEA revised its tables back to 1929 in to order to count:
1 Artistic Works
2 Research and Development
as Capital Investments that Depreciate Over Time
rather than one time expenditures

From an Economy based on
(Industry and Manufacturing)
to one based on
(Knowledge and Information)

This comprehensive revision did not cause a large percentage jump.
The relative difference of actual amounts over time changed little.

1984q1	3,912.8	7,140.6	149
1984q2	4,015.0	7,266.0	150
1984q3	4,087.4	7,337.5	151
1984q4	4,147.6	7,396.0	152
1985q1	4,237.0	7,469.5	153
1985q2	4,302.3	7,537.9	154
1985q3	4,394.6	7,655.2	155
1985q4	4,453.1	7,712.6	156
1986q1	4,516.3	7,784.1	157
1986q2	4,555.2	7,819.8	158
1986q3	4,619.6	7,898.6	159
1986q4	4,669.4	7,939.5	160
1987q1	4,736.2	7,995.0	161
1987q2	4,821.5	8,084.7	162
1987q3	4,900.5	8,158.0	163
1987q4	5,022.7	8,292.7	164
1988q1	5,090.6	8,339.3	165
1988q2	5,207.7	8,449.5	166
1988q3	5,299.5	8,498.3	167
1988q4	5,412.7	8,610.9	168
1989q1	5,527.4	8,697.7	169
1989q2	5,628.4	8,766.1	170
1989q3	5,711.6	8,831.5	171
1989q4	5,763.4	8,850.2	172
1990q1	5,890.8	8,947.1	173
1990q2	5,974.7	8,981.7	174
1990q3	6,029.5	8,983.9	175
1990q4	6,023.3	8,907.4	176
1991q1	6,054.9	8,865.6	177
1991q2	6,143.6	8,934.4	178
1991q3	6,218.4	8,977.3	179
1991q4	6,279.3	9,016.4	180
1992q1	6,380.8	9,123.0	181
1992q2	6,492.3	9,223.5	182
1992q3	6,586.5	9,313.2	183
1992q4	6,697.6	9,406.5	184
1993q1	6,748.2	9,424.1	185
1993q2	6,829.6	9,480.1	186
1993q3	6,904.2	9,526.3	187
1993q4	7,032.8	9,653.5	188
1994q1	7,136.3	9,748.2	189
1994q2	7,269.8	9,881.4	190
1994q3	7,352.3	9,939.7	191
1994q4	7,476.7	##########	192
1995q1	7,545.3	##########	193
1995q2	7,604.9	##########	194
1995q3	7,706.5	##########	195
1995q4	7,799.5	##########	196
1996q1	7,893.1	##########	197
1996q2	8,061.5	##########	198
1996q3	8,159.0	##########	199
1996q4	8,287.1	##########	200
1997q1	8,402.1	##########	201
1997q2	8,551.9	##########	202
1997q3	8,691.8	##########	203
1997q4	8,788.3	##########	204
1998q1	8,889.7	##########	205
1998q2	8,994.7	##########	206
1998q3	9,146.5	##########	207
1998q4	9,325.7	##########	208
1999q1	9,447.1	##########	209
1999q2	9,557.0	##########	210
1999q3	9,712.3	##########	211
1999q4	9,926.1	##########	212
2000q1	10,031.0	##########	213
2000q2	10,278.3	##########	214
2000q3	10,357.4	##########	215
2000q4	10,472.3	##########	216
2001q1	10,508.1	##########	217
2001q2	10,638.4	##########	218
2001q3	10,639.5	##########	219
2001q4	10,701.3	##########	220
2002q1	10,834.4	##########	221
2002q2	10,934.8	##########	222
2002q3	11,037.1	##########	223
2002q4	11,103.8	##########	224
2003q1	11,230.1	##########	225
2003q2	11,370.7	##########	226
2003q3	11,625.1	##########	227
2003q4	11,816.8	##########	228
2004q1	11,988.4	##########	229
2004q2	12,181.4	##########	230
2004q3	12,367.7	##########	231
2004q4	12,562.2	##########	232
2005q1	12,813.7	##########	233
2005q2	12,974.1	##########	234
2005q3	13,205.4	##########	235
2005q4	13,381.6	##########	236
2006q1	13,648.9	##########	237
2006q2	13,799.8	##########	238
2006q3	13,908.5	##########	239
2006q4	14,066.4	##########	240
2007q1	14,233.2	##########	241
2007q2	14,422.3	##########	242
2007q3	14,569.7	##########	243
2007q4	14,685.3	##########	244
2008q1	14,668.4	##########	245
2008q2	14,813.0	##########	246
2008q3	14,843.0	##########	247
2008q4	14,549.9	##########	248
2009q1	14,383.9	##########	249
2009q2	14,340.4	##########	250
2009q3	14,384.1	##########	251
2009q4	14,566.5	##########	252
2010q1	14,681.1	##########	253
2010q2	14,888.6	##########	254
2010q3	15,057.7	##########	255
2010q4	15,230.2	##########	256
2011q1	15,238.4	##########	257
2011q2	15,460.9	##########	258
2011q3	15,587.1	##########	259
2011q4	15,785.3	##########	260
2012q1	15,973.9	##########	261
2012q2	16,121.9	##########	262
2012q3	16,227.9	##########	263
2012q4	16,297.3	##########	264
2013q1	16,475.4	##########	265
2013q2	16,541.4	##########	266
2013q3	16,749.3	##########	267
2013q4	16,999.9	##########	268
2014q1	17,025.2	##########	269
2014q2	17,285.6	##########	270
2014q3	17,569.4	##########	271
2014q4	17,692.2	##########	272
2015q1	17,783.6	##########	273
2015q2	17,998.3	##########	274
2015q3	18,141.9	##########	275
2015q4	18,222.8	##########	276
2016q1	18,281.6	##########	276
2016q2	18,450.1	##########	276
2016q3	18,675.3	##########	276

CASE: UE 319
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 506

Staff CAPM Results (Capital Asset Pricing Model)

Exhibits in Support Of Opening Testimony

June 16, 2017

Capital Asset Pricing Model (CAPM)

Staff's Representative CAPM Modeling Results

Information from this model:

Best Point ROE may not be Top Modeling Value

	Copnsidered	
	3.68%	Risk Free Rate (R_f) as Average of Bloomberg January 2017 daily market forwards for June 1, 2018 effective 10 Yr UST Yields
Selected	4.30%	R_f as Average of Bloomberg January 2017 daily market forwards for June 1, 2018 effective 30 Yr UST Yields
Selected	4.50%	Ibbotson Market Risk Premium (Since 1980 — My Adult Lifetime)
	6.00%	Morningstar in Stocks, Bonds, Bills and Inflation 2015 Classic Yearbook (Very Long Run since 1926)

$R_{PGE} = R_f$+Beta*MRP

	Screen #	Abbreviated Utility	Ticker	Selected: VL 3/27/2017 Beta	Considered: Yahoo Fin. 3/24/2017 Beta	UE 319 PGE	UE 319 Staff	Ibbotson 30 Yr UST Forward R_f CAPM w VL Beta	Morningstar 30 Yr UST Forward R_f CAPM w VL Beta	Screen #	
1	1	AEP	AEP	0.65	0.14	Yes	No	7.23%	8.20%	1	1
2	2	Allete	ALE	0.80	0.26	Yes	No	7.90%	9.10%	2	2
3	3	Alliant	LNT	0.70	0.38	Yes	No	7.45%	8.50%	3	3
4	4	Ameren	AEE	0.70	0.29	Yes	Yes	7.45%	8.50%	4	4
5	7	CenterPoint	CNP	0.85	0.57	Yes	No	8.13%	9.40%	7	5
6	9	CMS	CMS	0.65	0.12	Yes	No	7.23%	8.20%	9	6
7	10	Consol Ed	ED	0.55	-0.03	Yes	No	6.78%	7.60%	10	7
8	11	Dominion	D	0.70	0.24	Yes	No	7.45%	8.50%	11	8
9	12	DTE	DTE	0.65	0.12	Yes	No	7.23%	8.20%	12	9
10	14	Edison Int'l	EIX	0.65	0.11	Yes	Yes	7.23%	8.20%	14	10
11	15	El Paso	EE	0.70	0.45	Yes	Yes	7.45%	8.50%	15	11
12	17	Entergy	ETR	0.65	0.67	Yes	No	7.23%	8.20%	17	12
13	23	IDACORP	IDA	0.75	0.31	Yes	Yes	7.68%	8.80%	23	13
14	26	MGE	MGEE	0.70	0.13	Yes	No	7.45%	8.50%	26	14
15	29	OGE	OGE	0.95	0.82	Yes	No	8.58%	10.00%	29	15
16	30	Otter Tail	OTTR	0.85	0.51	Yes	No	8.13%	9.40%	30	16
17	32	PG&E	PCG	0.65	0.15	Yes	Yes	7.23%	8.20%	32	17
18	33	PGE	POR	0.70	0.14	Yes	No	7.45%	8.50%	33	18
19	34	Pinnacle	PNW	0.70	0.23	Yes	No	7.45%	8.50%	34	19
20	35	PNM	PNM	0.75	0.18	No	Yes	7.68%	8.80%	35	20
21	36	PPL	PPL	0.70	0.55	Yes	No	7.45%	8.50%	36	21
22	37	Public Serv.	PEG	0.70	0.34	Yes	No	7.45%	8.50%	37	22
23	38	SCANA	SCG	0.65	0.12	Yes	No	7.23%	8.20%	38	23
24	39	Sempra	SRE	0.80	0.63	Yes	No	7.90%	9.10%	39	24
25	44	Vectren	VVC	0.75	0.74	Yes	No	7.68%	8.80%	44	25
26	47	Xcel	XEL	0.60	0.08	Yes	No	7.00%	7.90%	47	26
							Staff Peer Screen	7.45%	8.50%		
							Sensitivity Mid Cap	7.60%	8.70%		
							Company Screen	7.51%	8.58%		

CASE: UE 319
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 507

Cost of Long-Term Debt

Exhibits in Support
of Opening Testimony

NON-CONFIDENTIAL
June 16, 2017

Abbreviations Used by Staff:

10-K	Annual Report AVA files with the SEC (2012 unless specified otherwise)
10-Q	Quarterly Report AVA files with the SEC (2012 Q1 unless specified otherwise)
AVA	Avista Corporation (NYSE: AVA)
BB	Bloomberg
Cpn	Coupon Rate (Percent)
Curr	Currency
CUSIP	Committee on Uniform Securities Identification Procedures Security Identification
Ecova	Ecova, Inc. (Former Indirect Subsidiary of AVA)
EIN	IRS Employer Identification Number
FMB	First Mortgage Bonds
Freq	Frequency
IRS	U.S. Internal Revenue Service
Key	SNL Funding Key (Identification Number)
LT	Long-Term
MTN	Medium Term Notes
N/A	Not Available
N/R	Not Rated
NYSE	New York Stock Exchange (Ticker Symbol)
PCRB	Pollution Control Revenue Bonds
SEC	U.S. Securities and Exchange Commission (File Number)
SE	Spokane Energy (AVA owns all capital of this Special Purpose Limited Liability Company)
SNL	SNL Financial, LC
U.S.	United States of America
USD	US Dollar (Denominated)
WD	Withdrawn (Credit Rating)

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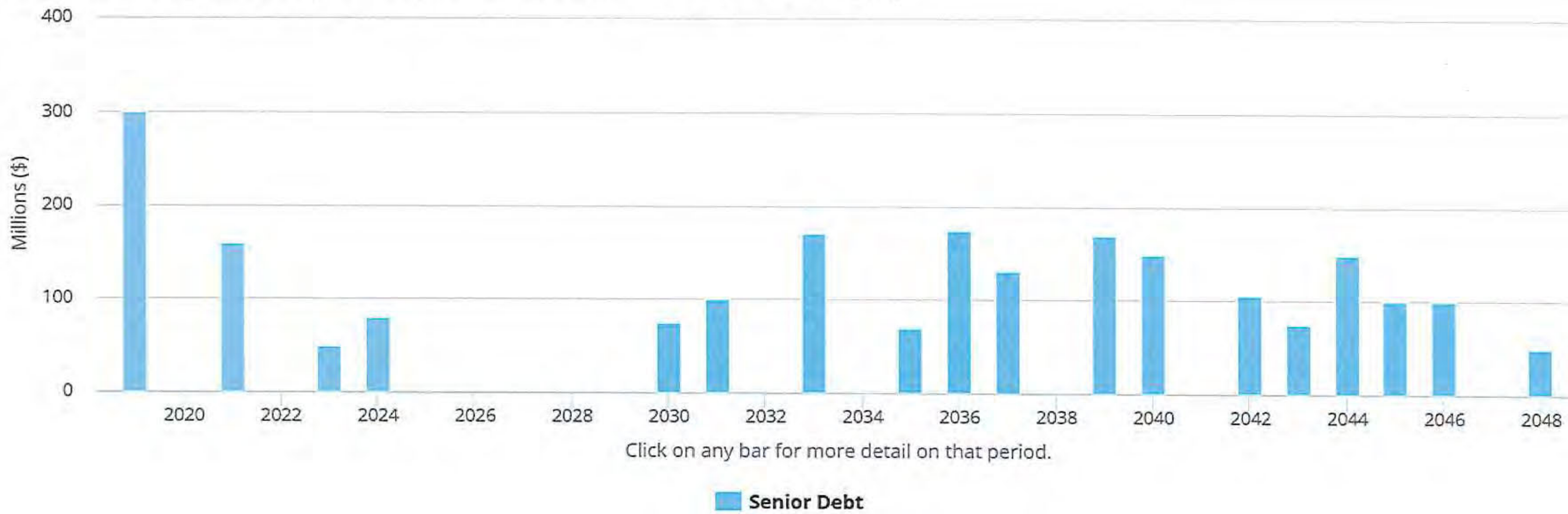
Is subject to Protective Order No.17-057

SNL Financial LC - Profile Prior to Planned 2017 Issuances and Staff ProForma 2018 Adjustment, and excluding $20 M of 9.31% Series Due Aug. 11, 2021.

https://www.snl.com/web/client?auth=inherit#company/debtMaturityProfile?ID=4057019 Accessed by Staff on May 17, 2017

Debt Maturity Profile (Data displayed in USD)

(Includes outstanding notes, bonds, and trust preferreds with original maturity greater than 1 year)



This profile is a snapshot by SNL prior to PGE's planned debt and prior to Staff pro forma adjustments addressing the current portion of LT Debt in the test year.

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CASE: UE 319
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 508

Examples of Mergers and Acquisitions in Utilities Followed by VL

Exhibits in Support of Opening Testimony

June 16, 2017

Southern/AGL Merger Settlement Reached in New Jersey; Closing Expected in Q2'16

by Phoebe Magdirila — SNL Financial LC — May 5, 2016

Southern Co. and **AGL** Resources Inc. have reached an **agreement with all parties in the** companies' New Jersey **merger** proceeding, putting **the deal on track to close in the second half of 2016**.

The merger is expected to close **following New Jersey Board** of **Public Utilities** and **Illinois Commerce Commission approval** of the **settlements reached in those** respective **jurisdictions**, according to a May 5 news release.

The companies sought approval from the New Jersey and Illinois regulators in October 2015.

In a separate release the same day, **Southern said it expects to raise about $900 million from an underwritten public offering of 18,300,000 shares of its common stock** and use a portion of the net proceeds **to fund the AGL acquisition**. The offering is expected to close May 11, subject to customary closing conditions.

Citigroup and **J.P. Morgan** are acting as **joint book-running managers** for the offering.

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Duke Energy Closes $6.7B Acquisition of Piedmont Natural Gas

By Darren Sweeney — SNL Financial LC — Oct. 3, 2016

Duke Energy Corp. has **completed** its **$6.7 billion acquisition** of **Piedmont** Natural Gas Co. Inc.

The Oct. 3 announcement comes days after the **North Carolina Utilities Commission** issued an order **Sept. 29 approving** the **merger**. (Docket Nos. E-2, SUB 1095; E-7, SUB 1000; G-9 SUB 682)

Approval by North Carolina regulators was the **final regulatory hurdle** for the deal.

The combination previously received approvals from the Tennessee Regulatory Authority and Piedmont shareholders, as well as the Federal Trade Commission.

Piedmont will **retain** its **name** and will **operate** as a **business unit** of **Duke** Energy. Piedmont serves about 1 million natural gas customers in North Carolina, South Carolina and Tennessee and, like Duke, is headquartered in Charlotte, N.C.

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Canada's AltaGas in Talks to Combine with D.C. Utility WGL

by Matt Jarzemsky and Dama Cimilluca — WSJ — Jan. 12, 2017

Canada's **AltaGas** Ltd. is **in talks to combine with WGL** Holdings Inc. in a **transaction** that **could value** the **parent of Washington, D.C.'s natural-gas utility at $5** billion to **$6 billion**, as increasing use of natural gas spurs merger activity.

A **deal could be announced this month**, people familiar with the matter said—assuming the talks don't fall apart and another bidder doesn't re-emerge. WGL has been considering a sale for months.

In a statement after The Wall Street Journal reported on the talks Thursday, AltaGas said "While we are in discussions regarding a potential transaction with a third party, no agreement has been reached and there is **no assurance** that these discussions will continue or that any **transaction will be agreed upon**." A WGL spokesman declined to comment.

WGL operates Washington Gas, a utility founded through a congressional charter in 1848, according to its website. The company installed gas lights in the House and Senate chambers and the White House, and later expanded into Virginia and Maryland. Washington Gas now has more than **1 million customers in** the **D.C. area**. WGL also provides retail energy-marketing services and operates natural-gas distribution facilities.

Calgary-based AltaGas operates utilities that serve more than 560,000 customers, according to its website. The company has been diversifying in recent years beyond its roots in natural-gas processing facilities and electric-power plants. **In 2012**, it **paid** about **$800 million for** the **parent of two natural-gas distributors**, **Michigan's Semco** and **Alaska's Enstar**.

Growth in natural-gas use by homes and businesses has fueled **takeover interest among large utility operators and power companies**, particularly those struggling with stagnant electricity sales.

Last year, Dominion Resources Inc. **bought Questar** Corp. for about **$4.4 billion**, **Duke** Energy Corp. **bought Piedmont** Natural Gas Co. **for $4.8 billion** and **Southern** Co. **bought AGL** Resources Inc.

A price in the $5 billion to $6 billion range could mark a **significant premium** for **WGL**. The company had a **market value Thursday** afternoon of about **$3.9 billion**, a figure that had already received a lift from the prospect of a sale. Bloomberg reported in November that WGL was considering a sale after fielding **interest from Iberdrola** SA. Discussions with the Spanish company **fell apart**, a person familiar with the matter said this week. WGL shares jumped nearly 6 percent Thursday on news of the potential deal to close at $80.26.

A **purchase of WGL** would be a **big bite for AltaGas**, which is **valued at** about 5.6 billion Canadian dollars (**US$4.3 billion**). **AltaGas** also has a hefty **debt load** of

C$3.8 billion, but its Toronto-traded shares were up 20 percent in the past year, which could increase its ammunition for a deal.

Regulatory or political pushback is seen as a **potential obstacle** to any proposed tie-up between WGL and AltaGas, one of the people familiar with the matter said. Exelon Corp. spent nearly two years seeking approval from D.C. regulators for its nearly $7 billion purchase of Pepco Holdings Inc., a deal that closed in March. AltaGas also may seek the blessing of the **Committee on Foreign Investment** in the U.S., which **screens takeovers by foreign acquirers** for security concerns, according to this person.

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CenterPoint Energy Acquires Atmos Energy's Gas Marketing Business

by Selene Balasta — SNL Financial LC — Jan. 4, 2016

CenterPoint Energy Inc. unit CenterPoint Energy Services Inc. **closed** its **purchase** of **Atmos Energy Marketing** LLC **from Atmos Energy Holdings** Inc., according to a Jan. 3 news release.

Under an **all-cash transaction of $40 million plus working capital**, **Atmos Energy** Corp. **has fully exited its nonregulated gas marketing business** and **has become a fully regulated pure-play gas company**. The transaction includes the transfer of about 800 delivered gas customers and Atmos Energy Marketing's related asset optimization business.

"This transaction is a strategic fit for both CES and AEM, and the acquisition will enable CES to more effectively access new markets and customer segments, grow our customer base and gross margins, and maintain our low value-at-risk, cost-effective organizational structure. AEM's complementary operational and geographic footprints will provide CES with increased scale, geographic reach, and expanded capabilities that will enable it to grow, while maintaining a focus on excellent customer service," CenterPoint vice president Joe Vortherms said in the release.

With the completion of the deal, CenterPoint Energy Services now operates in 32 states and will deliver in excess of 1 trillion cubic feet of natural gas to approximately 100,000 customers annually.

Power Company Calpine Explores Sale

by Dana Mattioli and Matt Jarzensky – WSJ – May 10, 2017

Calpine is working with Lazard to sound out possible buyers.

The Houston company, which **owns 80 power plants** and has a so-called enterprise value of more than $15 billion, is working with investment bankers at Lazard to sound out possible buyers, according to people familiar with the matter. Calpine has attracted interest from a number of private-equity firms in an auction that is at an early stage, the people said. As always, there is no guarantee there will be any deal.

Calpine sells power and related services to wholesale customers — including utilities and industrial and agricultural companies — and retail affiliates.

As of Wednesday afternoon, Calpine had a **market value of $3.6 billion**; at the end of March, it had some **$12 billion of debt**, which the company has been seeking to whittle away.

Calpine, founded in 1984, owns and operates **mainly natural-gas-fired power plants**. According to its annual report, the company is one of the top consumers of natural gas in North America, accounting for an estimated 8% of consumption in the region last year.

The company filed for **bankruptcy in 2005**, **burdened by** $17 billion in **debt** as soaring natural-gas prices made its fleet of power plants more costly to operate. The company had expanded aggressively starting in the mid-1990s, with a goal of becoming the largest U.S. power generator.

Lately Calpine, which emerged from bankruptcy in 2008, has been **slashing costs and unloading noncore assets** as the shares slump.

On **Wednesday** afternoon, the **stock** changed hands for **about $10.15**, **down from more than $24 at one point in 2014. Over the last year, the shares have declined more than 33%**.

In the **first quarter, Calpine reported a net loss of $56 million**.

Calpine has been expanding its retail platform through a number of acquisitions in recent years. As of the **end of last year**, its **retail subsidiaries served the equivalent of about 6.5 million residential customers in Texas, California, the northeast and elsewhere**, according to Calpine's annual report and its web site.

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Kan. Regulators Reject Great Plains Purchase of Westar Energy

by Lauren Bellero — SNL Financial LC — Apr. 19, 2017

Kansas state regulators on April 19 dealt a blow to the **proposed merger between Westar** Energy Inc. **and Great Plains** Energy Inc., **concluding** that the **transaction** is **not in the best interest of the public**.

The **deal** is "**too risky**," the Kansas Corporation Commission said in rejecting the merger.

According to the KCC's order, "**substantial competent evidence**" indicated that **Great Plains would be financially weaker if the transaction were to proceed**. The companies asked the regulators to "trust their raw estimates and projections," but the KCC felt it could not take that risk because **if** those **predictions** are "**overly rosy**, the **customers will face higher rates or decreased service**," the order said.

The **KCC called** the **application** "**deficient**" and stated that it lacked any formal plan to retire power plants early, which was key to the proposed savings by the companies.

Additionally, with the large amount of debt Great Plains would take on to acquire Westar, the KCC found there to be "**no examples of reduced spending through procurement savings** and **no evidence that customers will see any savings**." The companies also **did not provide** the KCC with **enough evidence** to **show Great Plains** will be **able to service the newly incurred debt without imposing rate increases or cutting back on service**, the order said.

Great Plains announced May 31, 2016, that it planned to acquire Westar Energy in an **$8.6 billion** cash-and-stock **deal**. Great Plains **also** would **assume** approximately **$3.6 billion in Westar** debt. **Great Plains' utility subsidiary Kansas City Power & Light Co. operates in Missouri and Kansas**.

The **companies told** the **KCC** in June 2016 that the **merger would benefit customers** and "**result in significant savings, economies of scale, and efficiencies**

from the elimination of duplicate corporate and administrative services, all of which will **ultimately** result in a **lower cost of operations**." They said the transaction would create savings that would result in lower rates than if Westar and Great Plains continued to operate separately.

Several months later, however, **KCC** staff recommended that the proposed merger be rejected as not in the public interest. **Staff said** the **merger raises several concerns**, including with respect to the **two companies' ability** to **maintain** and **improve** the **quality of service** currently provided to Kansas customers **while reducing operating costs**. Staff also found **problems with** the joint applicants' **projected savings** calculation, among other things.

However, in testimony filed with the KCC in January, the heads of both companies stood firm in their belief that the proposed merger could have a positive impact on ratepayers in Kansas and on the state's economy. Westar Energy President and CEO Mark Ruelle said it could help stem rising electricity costs for consumers in the state. Great Plains Chairman, President and CEO Terry Bassham said that as part of the transaction, financial commitments were made to protect customers in the state from merger-related risks.

The **Missouri Public Service Commission has yet to rule on** the **deal**. The PSC concluded Feb. 16 that it has jurisdiction over the proposed merger and said it would require Great Plains to formally file an acquisition application. That conclusion was based on a section of a 2001 stipulation agreement in which the company said it would not acquire a public utility without requesting or receiving prior approval from the PSC.

Westar is headquartered in Kansas and **solely serves customers in that state**. **Great Plains** is **headquartered** in **Missouri** and has **utility operations in both Missouri and Kansas, but** has **argued** that **Missouri regulators do not have jurisdiction over the deal because no assets in that state are being acquired**.

Great Plains filed the required application with the PSC on Feb. 23 and a **final decision** is **expected after April 21**.

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Kan. Commission Denies Great Plains' Request to Reconsider Merger Order

by Russell Ernst – Regulatory Research Associates (RRA) – May 23, 2017
An Affiliate of SNL Financial LC and S&P Global Market Intelligence

On May 23, the **Kansas Corporation Commission**, or **KCC**, **rejected Great Plains Energy Inc.'s May 4 request for reconsideration** of the KCC's April 19 **order rejecting** the company's **proposed acquisition** of **Westar** Energy Inc.. The KCC had determined, in Docket No. 16-KCPE-593-ACQ that the transaction was **not in the public interest** and would have been "**too risky**."

In its instant order, the **KCC acknowledged that Great Plains and Westar are "responsible companies that serve their communities**. ...**However**, to promote the public interest, a proposed transaction must satisfy the merger standards." The commission stated, "As the Joint Applicants acknowledge in their Petition for Reconsideration, they would have to substantially change their application and supply a wealth of new evidence to satisfy the merger standards. ...The **Joint Applicants' Petition for Reconsideration fails to allege any specific defects with the Order or that the Order was in any way unlawful or unreasonable**. Instead, by its own admission, the Joint Applicants' pleading **merely seeks additional time** to determine if it is possible to develop a new proposed transaction." The KCC concluded that "**Under Kansas law**, the only option available to the Commission is **denial**."

Perhaps signaling that a revised deal between the companies could be palatable to the commission, the **KCC** noted that it "**encourages** the **parties** to **continue working together** to **'revise the Transaction** to **address** the **Commission's concerns** related to **purchase price**, **capital structure** and **other issues'** and **welcomes** the **filing** of a **new application that can satisfy the merger standards and advance the public interest**."

In its request for reconsideration, Great Plains had sought KCC permission to possibly "revise the Transaction to address the Commission's concerns related to purchase price, capital structure and other issues and ... provide additional information for discovery by Commission Staff and other parties to address concerns raised by the Commission in the Order."

Great Plains said it was aware that for any revised transaction to be approved by the KCC, as per the commission's April 19 order, the **purchase price would need to be lower**, the company's **capital structure would have to include a lower proportion of debt** than originally proposed and any **quantifiable customer benefits would need to be demonstrated.**

In addition, Great Plains said it respects "the Commission's finding that by relying on pre-bid savings estimates and not providing more detailed integration and savings plans in the record, [the company] hindered the ability of the Commission and the parties adequately to review and evaluate Transaction savings. ...Detailed integration plans and savings estimates have been fully developed and are now available for review and evaluation by the parties and presentation to the Commission."

The deal has been highly contentious since it was announced May 31, 2016. As noted below, there was considerable resistance to the deal in Kansas, and the companies initially contended that the acquisition did not require approval by the Missouri Public Service Commission. However, the PSC subsequently exercised authority over the deal, although to this point, the commission has not rendered a decision on the transaction.

For details on past mergers that have been considered by the KCC and the PSC, refer to the July 19, 2016, topical special report, "Electric and Gas Utility Mergers and Acquisitions — Timeline of Transactions 1985-2016."

Transaction details

On May 31, 2016, Great Plains and Westar announced an agreement whereby Great **Plains would acquire Westar for $12.2 billion**, **including $3.6 billion of assumed debt**. Westar shareholders would receive $60 per share of total consideration for each share of their common stock, consisting of $51 in cash and $9 in Great Plains Energy common stock.

A 7.5% collar would apply to the exchange ratio for the stock consideration, based on Great Plains' stock price at the time of the closing of the deal, such that the exchange ratio would range from 0.2709 to 0.3148 share of Great Plains stock for each share of Westar's stock, representing a consideration mix of 85% cash and 15% stock. The aggregate purchase price represents a **13.4% premium to Westar's May 27, 2016, closing price and a 36% premium to the closing price on March 9, 2016**, the day before news leaked that the company was exploring strategic alternatives that could lead to its sale. **Following completion of the deal, Westar would become a subsidiary of Great Plains**. The transaction was **unanimously approved by the boards of directors of both companies**.

The transaction was also subject to review by the **F**ederal **Energy R**egulatory **Commission**, the **Nuclear Reg**ulatory **Com**mission and the companies' shareholders, and was subject to the expiration or termination of the **waiting period** under the **Hart**-Scott-Rodino Act. Assuming all necessary approvals were obtained, the companies anticipated closing the transaction in spring 2017.

For further details pertaining to the deal, refer to the June 1, 2016, special report, Great Plains Energy/Westar Energy: Proposed **merger of two similarly sized electric utility holding companies**.

Kansas Jurisdictional Review

On June 28, 2016, Great Plains and Westar filed for KCC approval of their proposed merger. The companies proposed certain commitments designed to secure KCC approval of the transaction. In reviewing a proposed merger, the KCC is required to consider whether the transaction would promote the public interest.

On Aug. 9, 2016, the KCC issued an order reaffirming the jurisdiction's merger standards and requested the companies "identify any deviation from the restated merger standards" in supporting testimony. Great Plains and Westar subsequently notified the KCC that they "accept the standards enumerated by the Commission and believe they have addressed those standards" in their merger application.

On Sept. 9, 2016, the **staff** responded to the companies' claim that their application satisfied the requisite standards, and **opined** that the **companies should either amend** their **application** to conform to the merger standards **or** alternatively, the **application should be dismissed without prejudice**. The **Citizens' Utility Board** indicated that it **concurred with** the **staff's position** on the matter.

On Dec. 16, 2016, the **staff recommended** that the **proposed acquisition be rejected**, as the deal "depends in large part on the retention of savings generated by financial engineering." In addition, the staff contended that the deal is "so fragile that it cannot afford many of the typical rate concessions this Commission has required in previously approved large merger cases (rate moratoriums, cash rebates for anticipated savings, etc.) and still live up to the expectations it has set for investors." The staff indicated that it could not support approval of the deal, even with conditions that are typically imposed in the context of utility merger proceedings as its concerns are "incurable."

On Jan. 9, the companies filed rebuttal testimony in which they countered the staff's earlier recommendation. On April 19, the KCC issued its order rejecting the deal.

Origins of Missouri Jurisdictional Review

Great Plains and Westar initially indicated that the transaction would not be subject to review by the PSC; however, the commission subsequently granted a staff motion for the commission to conduct an investigation into the potential impact of the deal on Missouri ratepayers.

On June 8, 2016, the PSC opened an investigation, in Case No. EM-2016-0324, into the potential impact on Missouri ratepayers of the proposed acquisition. At the time, the PSC indicated the 2001 order that permitted KCP&L to restructure its operations into a holding company, Great Plains, with subsidiaries that include Kansas City Power & Light Co., or KCP&L, required the company to file "all information needed" to allow the PSC to determine whether there could be an adverse impact from the proposed deal on Missouri ratepayers.

On July 25, 2016, the staff filed a report in which it opined that the 2001 PSC order effectively gives the commission jurisdiction over the deal. The staff contended that the transaction, as initially structured, offered "no benefits to Missouri ratepayers and many potential detriments." In light of its findings, the staff recommended that the PSC "sanction" Great Plains for failing to comply with the conditions in the 2001 order and "protect" Missouri ratepayers from the adverse consequences of the proposed acquisition.

On Aug. 3, 2016, the PSC required that the case be closed and found that the proceeding was only an "investigatory docket, not a case, contested or otherwise."

On Oct. 12, 2016, KCP&L, GMO and the staff filed a settlement, in Case No. EE-2017-0113, that addressed the concerns the staff had expressed regarding the transaction. The settlement focuses primarily on ring-fencing provisions and the utilities' recovery of certain costs associated with the transaction. As called for in the settlement, the PSC has been considering a request for a variance of certain commission affiliate transaction rules as they relate to the deal. On Oct. 26, 2016, the companies and the Missouri Office of the Public Counsel filed a separate settlement that included additional provisions beyond those contained in the earlier settlement. Certain other parties objected to the settlements, and as such, the PSC was required to treat the settlements as the stipulating parties' positions on the merger.

On Jan. 4, the PSC ordered the staff to review the points of contention in the Kansas jurisdictional review of the deal. On Jan. 18, the staff filed its report and highlighted many of the concerns the KCC staff has with the proposed transaction, but suggested that two settlements previously filed in the Missouri proceeding are "designed to protect the interests of Missouri ratepayers and the State" and should be adopted by the PSC.

On Feb. 22, the PSC required Great Plains to formally file for commission approval of the proposed transaction, finding that Great Plains' claim that the Westar transaction was not subject to formal PSC review is "troublesome from a public policy perspective."

On Feb. 23, Great Plains requested PSC approval of the deal, which the company stated is "not detrimental to the public interest [thus meeting the applicable merger review standard in the state] and, in fact, will promote the public interest in many respects." Great Plains requested that Case Nos. EM-2017-0226 and EE-2017-0113 be consolidated, given that both proceedings "involve related questions of law and fact and consolidating the two cases will avoid unnecessary costs and delay." The commission subsequently approved the request.

The PSC's March 8 procedural order provided for briefs to be filed April 21, with a final PSC decision to be issued shortly thereafter.

On March 28, the Midwest Energy Consumers' Group notified the PSC that it was withdrawing as an intervenor in the consolidated merger review proceeding. The PSC's review of the proposed transaction is ongoing.

Overview of Company Operations

Great Plains is headquartered in Kansas City, Mo., and owns and operates nearly 6,500 MW of generation capacity. The company provides vertically integrated electric utility service to roughly 530,000 customers in Missouri and Kansas through KCP&L and 320,000 customers in Missouri through KCP&L Greater Missouri Operations Co.

Westar, headquartered in Topeka, Kan., owns and operates roughly 7,200 MW of generation capacity and provides vertically integrated electric service to approximately 700,000 customers in Kansas through its Westar Energy division and its Kansas Gas and Electric Co. subsidiary.

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Great Plains, Westar Extend Merger Closing by 6 Months

by Selene Balasta – SNL Financial LC – May 30, 2017

Great Plains Energy Inc. and **Westar** Energy Inc. have both **agreed to extend the completion date of their merger by six months, to Nov**. 30 from May 31.

According to separate May 30 8-K filings, Great Plains elected to delay the merger completion and Westar agreed, seeking more time "to determine if a mutually agreeable revised transaction might be negotiated." Other provisions of the merger remain in place, according to the filings.

On **May 23**, the **companies** were **denied extra time to renegotiate** the **proposed deal** as the **Kansas Corporation Commission refused to keep the docket open** and **reaffirmed** its **decision to reject the deal. In** an **April** 19 ruling, the **commission said** the **deal** was **too risky and not in the public interest**.

Great Plains announced May 31, 2016 that it planned to acquire Westar Energy in an **$8.6 billion cash-and-stock deal**. **Great Plains also** would **assume approximately $3.6 billion in Westar debt**.

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NextEra Tenders Bid for Rehearing of Texas PUC Order Rejecting Oncor Acquisition

by Lilian Federico – Regulatory Research Associates (RRA) – May 9, 2017
An Affiliate of SNL Financial LLC and S&P Global Market Intelligence.

On May 8, just under the statutory deadline, NextEra Energy Inc. filed for reconsideration of the April 13 Public Utility Commission of Texas order rejecting its proposed acquisition of Energy Future Holdings Corp., or EFH, parent of Oncor Electric Delivery Co. LLC.

NextEra said the order "contains a number of serious errors that require correction" and "represents an expansion of power that exceeds the limits set by the Legislature and the bounds of the Commission's own precedent."

NextEra alleges that the provisions of state law upon which the commission based its denial of the application do "not authorized that remedy." In addition, NextEra claims the order does not take into account all of the factors the commission is required to consider in performing its public interest analysis, and "sets forth a new, more stringent public interest standard ... that requires a showing of tangible benefits to ratepayers that are 'unique' and 'exclusive' to the transaction."

According to NextEra, the order's "ad hoc imposition of new requirements and the resulting findings and summary denial of the two separately negotiated transactions at issue stand in contrast to those in the order issued only last year, in [its review of the proposed acquisition of Oncor by a group of investors led by Hunt Consolidated Inc. parent of Sharyland Utilities LP], where the Commission found a proposed transaction to acquire Oncor ... to be in the public interest subject to certain conditions. The contrast is especially striking because the [Hunt] order found the transaction proposed there to be in the public interest despite evidence establishing that billions of dollars in debt entirely dependent on Oncor cash flows for servicing would continue to reside directly above Oncor and that Oncor would, at least initially, be owned by a non-investment grade entity. The transactions in this case would eliminate all of that debt through refinancing by a traditional utility holding company parent that is A- rated, widely diversified, and highly liquid with more than $7 billion of annual operating cash flows. Despite this evidence, the Order summarily denies NextEra Energy's proposed acquisition of Oncor outright."

NextEra said the commission "failed to give any consideration to the benefits and protections offered by NextEra Energy's 73 regulatory commitments — commitments that include and exceed many of those adopted by the Commission in [the Hunt proceeding] .... Notably, the Order denies these and other benefits of the proposed transactions because the Commission is unwilling to allow NextEra Energy to exercise governance control over Oncor, an entity in which NextEra Energy will invest $12.2 billion to acquire."

NextEra requests that the commission issue an order on rehearing "finding the proposed transaction to be in the public interest, and, in order to ensure sufficient time to consider the merits of this motion and encourage possible settlement discussions, NextEra Energy respectfully requests that the Commission extend the period for acting on this motion for rehearing to the maximum extent allowed by law."

However, the **filing does not include any indication that NextEra would offer any additional commitments** in order to secure approval of the transaction. Even if NextEra were to offer "enhanced" commitments, depending on the scope and impact of the revised concessions, approval by the EFH stakeholders and the U.S. Bankruptcy Court could be required.

At this juncture, **given** that the commission's denial reflected the commissioners' understanding that **NextEra was unwilling to compromise with respect to the main areas of concern** — namely, the **independence of Oncor's board of directors** and **maintenance of the pre-existing ring fence — Regulatory Research Associates views it as unlikely that the commission would grant the motion for rehearing, or that if granted, the rehearing process would result in a substantially different outcome**.

Further muddying the waters is the fact that Chairman Donna Nelson is slated to leave the commission May 15, in advance of its next open meeting, which is scheduled for May 18. It is unclear whether her departure could be delayed to address this "open issue" or what impact the lack of a full complement of commissioners would have on the process.

Gov. Greg Abbott, a Republican, could appoint a successor to fill the vacancy, but if that individual is appointed while the legislature is still in session, that individual could not serve until confirmed by the Senate. Historically, the governor has waited for the session to end before filling an open seat on the commission so the appointee may begin serving pending confirmation in the next session. The legislature is expected to adjourn May 29 and is not in session in 2018.

By law, in a contested rate case, a motion for rehearing may be filed within 25 days after the commission's final decision, unless extended. Replies to the motion for rehearing must be tendered within 40 days after the issuance of the final order in the case the motion refers to. The commission must respond to a motion for rehearing within 55 days after the issuance of the final order.

Based on these guidelines, other parties may file comments by May 23, and the deadline for commission action is June 7; the commission has a meeting scheduled for that date as well. **If the commission does not take action on or before June 7, the**

request for rehearing expires. NextEra could pursue review of the order in the courts, but RRA views this as unlikely.

The Public Utilities Commission order

The commission's April 13 order adopted, with one minor wording change, a draft order formally rejecting a proposed acquisition of Oncor by NextEra due to certain irreconcilable differences.

The order comes as **no surprise, as the commission had signaled that it would reject the proposal at its March 30 open meeting**, citing certain "deal breakers," issues on which the commission and NextEra management were unable to agree.

The commission conducted the merger review proceeding (Docket No. 46238) directly, rather than assigning it to the State Office of Administrative Hearings. While this accorded the commissioners an unusual opportunity to interact directly with NextEra management, it did not allow them to come to a meeting of the minds.

In fact, the opposite is true. At the March 30 hearing, the commissioners noted that during the hearings, NextEra management indicated that there were certain conditions to which it would not agree. While expressing appreciation for NextEra's candor, the **commissioners opined that the company's stance on the issues left the commission no choice but to reject the transaction as formulated**.

The order concluded that although NextEra is "well-regarded," the "expansive and diversified structure of NextEra Energy and its affiliates would subject Oncor to new and potentially substantial risks. NextEra Energy's method of financing the proposed transaction does not entirely eliminate the debt above Oncor, but merely refinances that debt with new debt ....The revenues of Oncor would continue to support the repayment of that debt, albeit to a lesser extent."

According to the commission, the "sole tangible and quantifiable benefit" offered by NextEra is a commitment to share 90% of the interest rate savings on Oncor's cost of debt with ratepayers until new rates reflecting the lower debt costs are implemented. The **commission opined that other benefits cited by NextEra had either not been quantified or are not exclusive to this transaction**.

With respect to the Oncor ring-fence, which has been a major issue of contention in this proceeding, NextEra sought to remove provisions of the existing ring-fence that would restrict NextEra's ability to appoint, remove or replace members of the Oncor board of directors and that allow certain shareholders to veto dividends declared by the Oncor board, as well as capital and operating budgets. NextEra claimed that retention of either of these provisions would prevent the desired linkage of the Oncor and NextEra credit profiles. This issue was one of the so-called deal breakers.

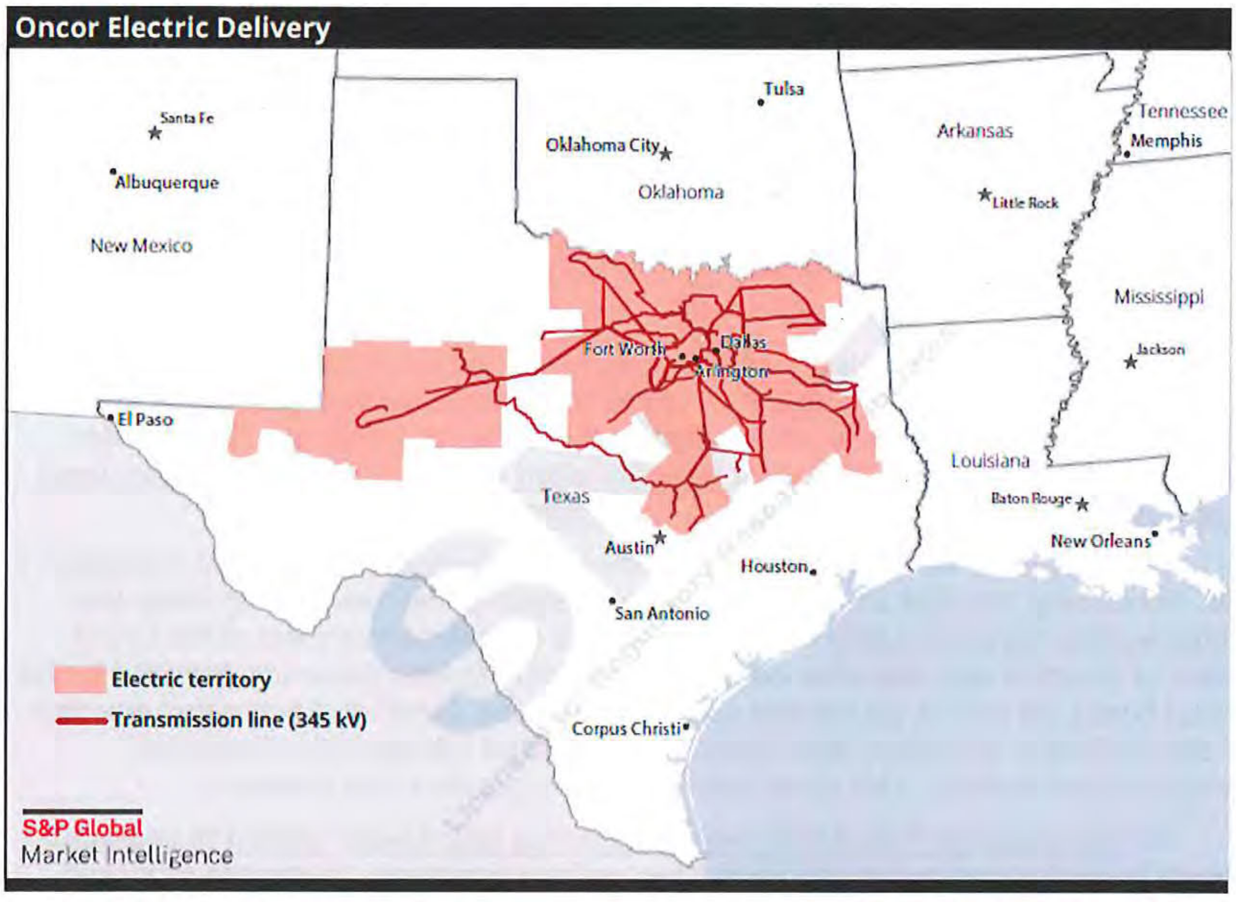
The **commission found that the existing ring fence was** "**critical in protecting Oncor from the bankruptcy of its indirect parent company**. Under the proposed transactions, a robust ring-fence is **still necessary** to protect Oncor if NextEra Energy or one of its subsidiaries were to file for bankruptcy."

In the end, the **commission concluded** that "**NextEra Energy ownership of Oncor would subject Oncor and its ratepayers to, significant new risks**. T he **tangible benefits** to Texas ratepayers that are specific to the proposed transactions are **minimal, and** would **do little to compensate ratepayers for any of the additional risks** imposed. When the Commission weighs the **additional risks and the lack of tangible benefits, combined with NextEra Energy's insistence on eliminating two critical ring-fencing protections**, the **Commission finds that the proposed transactions are not in the public interest, and the application is denied**."

Background of Oncor/EFH

Texas implemented retail competition for generation service in 2002, for the utilities whose service territories were part of the Electric Reliability Council of Texas, or ERCOT (see the Texas PUC Commission Profile for details).

As part of that plan, the existing companies were unbundled based on function, forming separate subsidiaries for transmission and distribution utility operations, power generation ownership and the provision of retail electric service, known as retail electric providers.



In 2008, the commission approved a settlement related to the leveraged buyout, or LBO, of TXU Corp., **then the parent of what is now Oncor**, by a consortium of private investors led by Kohlberg Kravis Roberts & Co. LP and TPG Inc.

Commission approval of the LBO was not required prior to the 2007 completion of the transaction. The **new company became known as EFH**.

However, the 2008 settlement included a **stringent ring-fence around Oncor**, in addition to substantial rate credits and write-offs. In addition, through Dec. 31, 2012, dividends paid by Oncor to the parent company were limited to "an amount not to exceed Oncor's net income." Oncor also agreed to certain capital spending requirements over the five years following the merger, as well as certain reliability and customer service standards.

The **commission prohibited Oncor from guaranteeing any new debt issued in conjunction with the transaction or thereafter**, and **directed that Oncor's debt ratio be maintained "at or below** the debt-to-equity ratio established from time to time by the Commission for ratemaking purposes," most recently **60% debt and 40% equity**, with **dividend payments to the parent to be limited if such payments would cause the debt ratio to rise above 60%**.

Largely due to reversals at its competitive businesses, **EFH** filed for **bankruptcy** protection under Title 11 of the U.S. Bankruptcy Code **in 2014**. Subsequent attempts to acquire Oncor have been tied to bankruptcy reorganization proposals.

In a failed attempt to acquire Oncor, in 2015, a consortium of investors led by Hunt Consolidated Inc. had proposed a transaction that would have restructured Oncor into a real estate investment trust, or REIT.

The utility commission conditionally approved the acquisition in March 2016 but set forth conditions designed to flow the tax benefits of the REIT structure to ratepayers, require commission approval of the lease transactions between the operating company and the asset company, and require the operating company and asset company to file joint rate cases. The ensuing litigation led certain participants in the bankruptcy reorganization plan to withdraw from the deal.

Hunt later came forward with an amended deal under which transmission and distribution operations would have been separated, with only the transmission business converted to a REIT.

The revised Hunt deal included a commitment to share with ratepayers 20% of the tax savings associated with the formation of the new REIT. Hunt also committed to keeping total debt at the holding companies above Oncor at or below $3.5 billion and debt levels at the transmission company holding company at or below $1.6 billion. Hunt also agreed to confer authority to the utility commission to regulate the internal leases, another key sticking point in prior negotiations.

However, before this deal could gain traction, the NextEra proposal was announced.

NextEra Proposal

Under the transaction, announced July 29, 2016, NextEra proposed to acquire EFH, Energy Future Intermediate Holding Co. LLC and its ownership interest in Oncor. NextEra also planned to spin off the merchant generation and retail electricity service businesses and retain Oncor as a principal business alongside its vertically integrated utility, Florida Power & Light Co.

NextEra already has a presence in Texas in the form of gas and wind generation, a retail electric provider and an electric transmission-only utility, Lone Star Transmission LLC.

NextEra also planned to acquire Texas Transmission Investment LLC and its approximately 20% indirect interest in Oncor. NextEra also agreed to acquire the remaining 0.22% indirect interest in Oncor that is owned by Oncor Management Investment LLC.

NextEra had proposed to remove the debt directly above Oncor and finance the $12.2 billion funding requirement with roughly 60% debt and 40% equity, and contended that the proposed transactions would not impact its financial strength and capabilities.

Oncor/NextEra filed for approval of the proposed transaction Oct. 31, 2016, and on Nov. 10, 2016, the utility commission indicated that it would hear the case directly.

The commission outlined the issues it was most concerned about early in the proceeding, among them federal income tax issues that were not as contentious in this proceeding as they had been in the Hunt proceeding, due to the traditional structure of the transaction. NextEra had already offered certain commitments with respect to debt reduction and maintenance of credit ratings, as well as capital investment and service quality commitments.

Intervening parties filed testimony in January 2017 supporting enhanced ring-fencing measures. Hearings were held in February, and briefs were filed in March.

The primary areas of contention were related to the composition of the post-merger Oncor board, the level of "independence" of that board, limitations on the ability of Oncor to make dividend payments to NextEra, the level of linkage between Oncor debt and parent company debt, and the timing of Oncor's next base rate case. The latter is largely moot as Oncor filed a base rate case March 17.

Public utility commission merger approval authority

Legislation enacted in 2007, requires utility commission preapproval before the completion of any merger involving an electric transmission and distribution utility, or any transaction under which more than 50% of the stock of a utility holding company would change hands.

Prior to that, commission approval was not required, but merger hopefuls generally tendered filings offering certain concessions. Interestingly, commission preapproval was not required of the LBO of TXU that created Oncor's existing structure.

In order to approve a transaction, the commission must determine that the transaction is in the public interest and will not adversely affect the health and safety of customers or employees, result in the transfer of jobs outside the state, or result in a decline in service.

The commission must also consider whether the utility will receive consideration equal to the reasonable value of the assets when it sells, leases or transfers assets, the **impact of the transaction on competitive markets** and the extent to which the transaction mitigates market power in either the retail or wholesale electricity market.

The commission must rule on a proposed transaction within 180 days. If it has not made a determination before the 181st day, the transaction is considered approved.

Figure 2: Canadian Peers - Comps Table

Canadian Utilities	Ticker	Rating	Market Cap. (CAD in Mn)	Price 4/25/2017	Price Target	Dividend Yield	Short Interest	P/E Multiple 2016E	2017E	2018E	2019E	2020E	Earnings Per Share 2016E	2017E	2018E	2019E	2020E
Fortis	FTS-ca	Not Rated	18,282	44.18	NA	3.62%	0.7%	19.0	17.8	17.1	16.7	16.1	2.33	2.48	2.59	2.64	2.74
Emera	EMA-ca	Not Rated	10,040	47.57	NA	4.39%	3.2%	17.2	17.6	15.9	15.2	14.4	2.77	2.70	3.00	3.14	3.29
Algonquin Power & Utilities Corp.	AQN-ca	Not Rated	4,778	12.81	NA	4.85%	0.6%	22.5	18.7	17.7	19.9	16.6	0.57	0.68	0.72	0.65	0.77
HydroOne	H-CA	Not Rated	14,283	23.99	NA	3.50%	2.0%	19.8	20.1	18.5	17.6	16.7	1.21	1.19	1.29	1.37	1.44
Average - Canadian Utilities						**4.29%**		**19.6**	**18.6**	**17.3**	**17.3**	**16.0**	**6.7%**	**2.5%**	**7.8%**	**2.5%**	**5.7%**
Average - Regulated US Utilities						**3.15%**		**20.2**	**19.6**	**18.4**	**17.5**	**16.6**	**3.8%**	**2.8%**	**5.8%**	**5.2%**	**5.7%**

Canadian YieldCos	Ticker	Rating	Market Cap. (CAD in Mn)	Price 4/25/2017	Price Target		Short Interest	2015E	Div Yield 2016E	2017E	2018E	2019E	2020E	Div Yield Growth 2016E	2017E	2018E	2019E	2020E
Tranasta Renewables	RNW-ca	Not Rated	3,535	15.77	NA	40.12%		5%	6%	6%	6%	6%	6%	7%	4%	4%	0%	0%
Brookfield Renewables	BEP.UT-ca	Not Rated	12,418	41.51	NA	55.71%		6%	6%	6%	6%	6%	6%	0%	10%	6%	0%	0%
Capital Power Corporation	CPX-ca	Not Rated	2,411	24.82	NA	99.77%		6%	6%	6%	7%	7%	7%	7%	7%	7%	0%	0%
Capstone Infrastructure Corporation	CSE-ca	Not Rated	1,114	4.89	NA	NA		na	na	na	na	na	na	na	na	na	na	na
Innergex Renewable Energy Inc.	INE-ca	Not Rated	1,512	13.95	NA	98.01%		4%	5%	5%	5%	5%	5%	3%	3%	2%	0%	0%
Average - Canadian YieldCos									**5%**	**6%**	**6%**	**6%**	**6%**					
Average - Primary YieldCos Ex- TERP									**6%**	**7%**	**7%**	**7%**	**7%**					

Source: FactSet

Figure 3: SMID Comp Set Incl. Texas

Small and Mid-Caps	Ticker	Rating	Market Cap	Price	PT	Div Yield	2016E	2017E	2018E	2019E	2020E	2016E	2017E	2018E	2019E	2020E	2016.0	2017E	2018E	2019E
ALLETE	ALE	Not Rated	3,616	71.09	NA	3.01%	20.6	19.3	18.4	16.7	16.4	3.46	3.68	3.87	4.26	4.33	10.6	13.0	12.8	12.0
Avista Corp	AVA	Sell	2,646	41.09	37.00	3.48%	19.1	21.7	19.8	18.3	17.6	2.15	1.89	2.07	2.24	2.33	9.5	10.4	9.9	9.2
Black Hills Corp	BKH	Not Rated	3,668	68.64	NA	2.59%	19.3	18.1	17.7	17.2	na	3.55	3.80	3.87	4.00	na	16.1	10.4	7.2	6.9
Great Plains Energy	GXP	Neutral	6,369	29.57	30.00	3.72%	17.6	19.1	16.8	16.2	15.8	1.68	1.55	1.76	1.82	1.87	7.6	7.6	8.3	8.0
Hawaiian Electric Industries	HE	Not Rated	3,674	33.79	NA	3.67%	20.5	18.9	17.9	17.3	16.5	1.65	1.79	1.89	1.95	2.05	8.1	9.9	10.0	9.5
Idacorp, Inc.	IDA	Not Rated	4,311	85.50	NA	2.57%	21.4	20.7	20.1	19.3	18.2	4.00	4.14	4.26	4.42	4.70	13.9	12.7	12.2	11.6
MGE Energy	MGEE	Not Rated	2,257	65.11	NA	1.89%	28.3	27.1	26.0	24.6	23.3	2.30	2.40	2.50	2.65	2.80	na	na	na	na
NorthWestern Corp	NWE	Not Rated	2,916	60.33	NA	3.48%	17.8	17.2	16.8	na	na	3.40	3.50	3.58	na	na	na	11.4	11.2	10.5
Portland General Electric Company	POR	Buy	4,132	46.40	47.00	2.76%	21.4	20.3	18.3	17.8	17.0	2.17	2.29	2.53	2.60	2.73	9.1	8.9	8.4	7.9
PNM Resources Inc.	PNM	Not Rated	3,041	38.18	NA	2.54%	20.9	19.0	18.2	17.3	na	1.82	2.01	2.10	2.21	na	10.0	8.8	8.3	8.2
Spire Inc	SR	Not Rated	3,186	69.65	NA	3.02%	19.8	19.0	18.5	17.1	na	3.52	3.67	3.76	4.07	na	12.4	10.4	9.9	8.6
OGE Energy Corp	OGE	Not Rated	7,008	35.09	NA	3.45%	18.1	17.2	16.4	16.0	15.5	1.94	2.04	2.14	2.19	2.27	na	na	na	na
Otter Tail Corp	OTTR	Not Rated	1,588	40.30	NA	3.18%	23.5	21.8	20.5	20.5	na	1.72	1.85	1.97	1.97	na	na	na	na	na
Vectren Corp	VVC	Not Rated	4,953	59.71	NA	2.81%	22.7	21.3	19.5	18.5	na	2.63	2.81	3.07	3.24	na	na	na	na	na
Texas SMID Peers																				
El Paso Electric Co.	EE	Not Rated	2,117	52.20	NA	2.38%	20.8	18.9	18.0	17.7	16.1	2.51	2.76	2.89	2.95	3.25	na	11.0	10.3	10.0
CenterPoint Energy, Inc.	CNP	Neutral	12,213	28.34	28.00	3.78%	na	na	na	na	na	na	na	na	na	na	na	na	na	na
Average						3.02%	20.78	19.97	18.88	18.18	17.37	*1.5%*	*4.3%*	*5.2%*	*2.9%*	*0.9%*	10.8	10.4	9.9	9.3

Source: UBS estimates for companies under coverage; all others are based on Factset consensus estimates

What will happen with the pending deals? Both already rejected

With both of the latest outstanding deals having recently been rejected (**GXP-WR** and **Oncor-NEE**) in recent weeks, the question is just whether there is a consistent trend beyond the points on leverage/credit profile? We say no. In fact, there is a cogent argument to be made that **the determinations arising out of the commissions could well have been notably different had companies both presented plans that didn't so substantially impact the consolidated company credit and/or present plans to meaningfully de-leverage** (mostly in the context of the GXP-WR deal). We note the **Oncor deal is different** in that consolidated credit quality of the pro-forma utility would have improved, but the **key ring fencing provisions required by utilities** would **not** have been **met**. We note **other utilities of late appear to be willing to take on these conditions of the ringfence**; the **question remains principally around control of the dividend and board**.

But both deals are seeking rehearing ...

It remains unclear precisely why t.he companies would pursue rehearing in their respective deals. We note in NEE's case the effort appears largely tied to its efforts to qualify for the $275 M termination fee Oncor would owe it should it make a best effort and be rejected by the PUCT (regulatory). In tandem for GXP, it remains unclear on this front precisely what angle will be pursued, with mgmt. indicating that they're assessing all options. In GXP's case, we wouldn't doubt demands for a more deliberated plan to de-leverage alongside other issues to address the core concerns as credible. That said, we believe mgmt. would not necessarily expand equity issuance to fund the WR acquisition in lieu of the full termination fee (not entirely a fungible decision).

How we do best position around these latest deals? WR best in near-term.

We see the best upside across the different scenarios to Westar, where a limited premium exists despite potential for any range of deal possibilities to return to the table. We note with the deal originally slated for $60/sh and our stand-alone valuation at $50/sh, shares are reflecting a very low likelihood already. We look for a rehearing appeal – and positioning of any new terms by next Thursday 4/4. While GXP would appear slightly cheap depending on core stand-alone EPS, we see the upside as less clear cut premised largely on a structural re-rating in historical earned ROEs. The question remains just how sustainable this nascent trend of improving earned ROEs remains after 2016?

Companies with intact growth focused on execution.

We note a core block of companies that have been substantially internally focused to achieve targets rather than pursue M&A. Among the best examples of this trend thus far has been AEP, which has escaped the trend among almost all of its closest market cap peers, focusing alternatively on divestment of its merchant biz and execution on its regulated growth targets.

DPS growth = a reflection of fewer organic and inorganic avenues

Is the latest trend towards higher payouts also an acknowledgement that M&A remains unpalatably expensive? We think so. We believe the **trend towards a higher payout ratio is illustrativ**e of not just **slowing organic prospects**, but

also acquisitive opportunities in light of current multiples paid (admittedly only modest against our estimates today on average given some starting off a **low DPS growth profile**). We see companies such as SRE, D, and NEE, among others poised to increase their DPS growth above that of their EPS growth as highlighting this trend (even while some execute on deals.) We wouldn't doubt peers to continue to see their payout ratios creep up on average across the wider sector. In fact, we believe DPS growth could be increasingly perceived as a cautious data point on prospects – with **shares seeing limited benefits from upticks in DPS growth across the sector**.

Who are the remaining smid-caps?

We actually see a **relatively limited universe of potential consolidation targets** with single-states remaining in the smid-cap bucket. We note that multi-state smids are likely more problematic given the need to ascertain approvals from all relevant regulators, potentially with each imposing their own specific requirements. For this reason, more concentrated, single-state, smids would appear to be deserving of a premium vs. more diversified stories.

We further caution that certain jurisdictions would appear more challenging: For instance in the latest rejection of the Oncor deal, we see peers in Texas as less likely to benefit from a consolidation premium, despite the run up in shares vs the group. We included a full list of Texas and SMID peers in Figure 3 above.

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WGL / AltaGas Seek Multistate Merger Approvals

by Lillian Federico and Monica Hinka – Regulatory Research Associates (RRA)
An affiliate of SNL Financial LLC and S&P Global Market Intelligence
April 27, 2017

In filings tendered with the District of Columbia Public Service Commission, the Maryland Public Service Commission and the Virginia State Corporation Commission, or SCC, on April 24, **WGL** Holdings Inc. and **Alta Gas** Ltd. **offered a series of commitments designed to garner regulatory support for the proposed transaction**.

The companies indicate that their proposed commitments are **designed to address issues raised by the commissions and intervenors** in other recently completed mergers, such as the 2016 acquisition of Pepco Holdings by Exelon Corp.

The commitments include **rate credits for customers in Washington, D.C**., **and Maryland**, **enhanced funding for customer assistance programs**, **employee guarantees**, and **ring-fencing and corporate governance provisions**, including the **creation of a bankruptcy-remote special purpose entity**.

The Transaction

After weeks of rumors, on Jan. 25, **Canadian energy company Alta Gas** Ltd. announced that it had reached an agreement **to acquire U.S. gas utility holding company WGL** Holdings Inc. for US$88.25 per share, in cash.

WGL is the parent of local gas distribution company, or LDC, **Washington Gas Light** Co., which has **operations in** the **District of Columbia, Maryland and Virginia**.

WGL also owns Hampshire Gas Co., a **pipeline company in West Virginia**, and other diversified energy services providers WGL Midstream Inc., WGL Energy Systems and WGL Energy Services. **Through WGL, AltaGas will acquire interests in four different pipelines in the Marcellus and Utica areas by 2019** and an agreement to provide 400 MMcf/d to the Cove Point LNG export facility. The pipelines, some of which are still under construction, will provide gas not only to customers in Virginia, but in the Northeast as well.

In addition to extensive electric and gas properties in Canada, **AltaGas is the parent of U.S. gas utility holding company SEMCO** Energy Inc., which in turn is the **parent of Enstar Natural Gas** Co., an **Alaska LDC**, and SEMCO Energy Gas, a Michigan LDC. **SEMCO also owns Alaska Pipeline** Co. **and Cook Inlet Natural Gas Storage Alaska** LLC.

The **transaction has been approved** by **both companies' boards of directors**, and **shareholder approval is expected** to be received at a meeting scheduled for May 10. Assuming all requisite approvals are granted, the transaction is expected to close in the second quarter of 2018.

Regulatory Reviews — Merger Standards

The **transaction** is **subject** to **review** by state **regulators** in the **District** of **Columbia**, **Maryland** and **Virginia**. The **Regulatory Commission of Alaska and** the **Michigan Public Service Commission** are **not required to review the transaction** since there will be **no change in the ownership of the utilities under their purview**.

District of Columbia PSC

Commissioners	Political party	Term ends
Betty Anne Kane, Chair	D	Jun-18
Willie Phillips	D	Jun-18
Richard Beverly	NA	Jun-20
Key facts		
Size of staff		75
RRA ranking		Below Average/1
Merger review standard		Net benefits
Merger review time frame (days)		NA

Data compiled as of April 27, 2017.
NA = not available
Source: RRA, an offering of S&P Global Market Intelligence

Maryland PSC

Commissioners	Political party	Term ends
W. Kevin Hughes, Chair	D	Jun-18
Harold Williams	D	Jun-17
Michael Richards	R	Jun-20
Anthony O'Donnell	R	Jun-21
Vacancy	NA	Jun-19
Key facts		
Size of staff		141
RRA ranking		Below Average/2
Merger review standard		Net benefits
Merger review time frame (days)		225

Data compiled as of April 27, 2017.
NA = not available
Source: RRA, an offering of S&P Global Market Intelligence

Mark C. Christie		Feb-22
Key facts		
Size of staff		600
RRA ranking		Above Average/2
Merger review standard		No harm
Merger review time frame (days)		NA

Data compiled as of April 27, 2017.
NA = not available
Source: RRA, an offering of S&P Global Market Intelligence

FERC Review is also required, and a filing was tendered to FERC on April 24, 2017.

The proposed transaction is also subject to expiration or other termination of the applicable waiting period under the **Hart-Scott-Rodino Antitrust** Improvements Act of 1976, **and** review by the **Committee on Foreign Investment** in the United States.

District of Columbia — Transactions involving the District's investor-owned utilities are subject to review by the PSC. Approval of a proposed merger requires a finding by the PSC that the proposed consolidation will be in the public interest. The **PSC has interpreted this standard** as requiring that the transaction provide "a **direct and tangible benefit to ratepayers**." There is **no statutory time frame** for a review to be completed.

Maryland — Historically, the PSC's authority over mergers was somewhat ambiguous. Legislation enacted in 2006 clarified and expanded the **PSC's authority over mergers** to specifically **include** transactions **between holding companies and acquisitions of a Maryland utility by an out-of-state entity**.

In order to approve a merger, the PSC must determine that the merger would **cause no harm** and would provide a **positive net benefit to ratepayers**. The PSC **must rule** on a merger application within **180 days of the filing** for approval; **however**, the **PSC may extend the deadline for up to 45 days**.

Virginia — By law, in order to secure SCC approval of a proposed merger involving a utility operating in the state, the **merging entities must demonstrate** that the **transaction will neither impair nor jeopardize** the provision of **adequate service**

to the public at just and reasonable rates. There is **no statutory time limit** within which the SCC must rule on a proposed merger.

In each jurisdiction, the companies have offered certain jurisdiction-specific commitments, in addition to broader service-territory-wide commitments and corporate governance provisions. These are summarized in the sections that follow.

Jurisdiction-Specific Merger Commitments

District of Columbia customer rate credit

Customer class	Credit per customer ($USD)
Residential	
Heating/Cooling	50
Non-heating/Non-cooling; Individual Metered Apts.	15
Other	34
Commercial & Industrial	
Small Heating/Cooling	127
Large Heating/Cooling	829
Non-heating/Non-cooling	259
Group Metered Apartments	
Small Heating/Cooling	143
Large Heating/Cooling	786
Non-heating/Non-cooling	248
Interruptible	127
Avg. total	77

Source: AltaGas, Formal Case 1142

District of Columbia — Formal Case 1142 — The companies would provide customers **one-time rate credits aggregating to $12.25 million among all customer classes, equating to roughly $77 per customer**. However, the credit would be "allocated in accordance with each class's cumulative non-gas revenues as determined by the Commission in Washington Gas's last base rate case."

AltaGas would contribute $2 million to fund and develop an **Affordable Housing Multifamily Natural Gas Initiative for D.C.**, and **would not seek recovery of costs associated with the initiative**.

Additionally, over a two year period following consummation of the merger, **AltaGas would provide $2.2 million to fund and develop supplemental low-income weatherization programs**.

For a two-year period following the close of the merger, **AltaGas would provide $700,000 to fund workforce development initiatives in D.C. AltaGas would not seek recovery of costs associated with the initiatives**.

A procedural conference has been set for May 18, at which time a procedural schedule is likely to be developed. There is **no statutory time limit within which the D.C. PSC** must rule on a proposed merger.

Maryland customer rate credit

Customer class	Credit per customer ($USD)
Residential	
Heating/Cooling	50
Non-heating	27
Commercial & Industrial	
Large Heating/Cooling	517
Small Heating/Cooling	78
Non-heating/Non-cooling	197
Group Metered Apartments	
Heating/Cooling	786
Non-heating/Non-cooling	137
Interruptible	5,987
Avg. total	66

Source: AltaGas, Case No. 9449

Maryland — Case No. 9449 — The Maryland-specific commitments include **$30.5 million in aggregate one-time rate credits for all customer classes, equating to roughly $50 per residential customer**. However, the credit would be "allocated in accordance with each class's cumulative non-gas revenues as determined by the Commission in Washington Gas's last base rate case."

In addition, the **companies would contribute $4 million to develop and fund an Affordable Housing Multifamily Natural Gas Initiative for Maryland**. The program would provide **offsets for the cost of design and financial modeling to utilize natural gas** as well as provide **cost offsets for inside customer piping**.

An **incremental $1.1 million would be expended over two years to develop and fund supplemental low-income weatherization and energy efficiency programs in** Washington Gas' **Maryland** service territory.

AltaGas would also provide $350,000 in incremental funding to Washington Gas, **recovery of which would not be sought from customers** for **educational and damage prevention awareness and safety**.

Over the two-year period after the merger closes, **AltaGas would expend $1.4 million on workforce development initiatives in** the **Maryland** service territory.

The Maryland PSC has set a pre-hearing conference for May 30, at which time a procedural schedule is likely to be developed. **Final action** by the PSC is required by **no later than Dec. 5**.

Virginia — Case No. PUR-2017-000049 — **Washington Gas would continue to make investments in its utility infrastructure at pre-merger levels** to ensure the continued delivery of safe and reliable service at reasonable rates to its customers.

The company's note that Washington Gas is on target to complete under its Steps to Advance Virginia's Energy, or SAVE Plan, approximately $185 million in investment in infrastructure replacements approved by the Commission for the period Jan. 1, 2015, through Dec. 31, 2017. During June or July 2017, Washington Gas intends to file an amended five-year SAVE Plan to be effective from Jan. 1, 2018. This amended plan is to build upon its existing set of Distribution Integrity Management Program-based replacement programs, as well as transmission facilities replacement programs, consistent with the availability of construction contractor resources.

Recovery of SAVE Act investments through Nov. 11 is to be rolled into base rates as part of a pending rate case. A "black box" settlement has been reached in the case that specifies a $34 million rate increase.

AltaGas would commit to expend $1.4 million over a two-year period following the close of the merger to fund workforce development initiatives in Virginia.

A procedural schedule has not yet been set and there is **no statutory time limit** within which the SCC must rule on a proposed merger.

Service Territory-Wide Commitments

The companies note that while "this is **not a synergies-driven Merger**, the **Applicants do anticipate that modest savings** for Washington Gas will be achieved. ... The **net savings achieved by Washington Gas as a result of the Merger will be passed on to its customers through the normal course of the ratemaking process**."

All customers of Washington Gas would be held harmless for a period of five years from adverse rate impacts due to an increase in Washington Gas's cost of debt that is caused by the merger.

Washington Gas would refrain from seeking recovery through gas distribution rates of any acquisition premium or "goodwill" associated with the transaction, or any **transaction costs incurred in connection with the merger**.

In any rate proceeding for the five year period after the merger closes, **any increase of Washington Gas' cost of debt for which rate recovery is sought will be supported by documentation showing that either the increase is a result of factors not associated with either the merger or the post-merger operations of AltaGas and its non-Washington Gas affiliates, or that the increase has been mitigated by positive changes in other cost of capital elements**.

The companies said there would be **no degradation in service quality as a result of the merger**. "After completion of the Merger, Washington Gas will continue to provide adequate, safe, reliable, and efficient utility service at just and reasonable rates to its customers. ... In addition, Washington Gas will **maintain safety standards** and **policies** at Washington Gas that are **substantially comparable to, or** better than, the **currently maintained standards and policies**," they said.

The companies would provide **$1.5 million of supplemental funding over the five years following the merger close to the Washington Area Fuel Fund to provide emergency gas utility bill assistance to qualifying low-income customers** and moderate-income customers.

Within five years after the close of the merger, AltaGas would "develop or cause to be developed" 5 MW of either electric grid energy storage or Tier 1 renewable resources in the greater Washington, D.C., metropolitan area.

The **company would also provide $450,000 for a study to assess the development of renewable gas facilities in the greater Washington, D.C., metropolitan area**.

In addition to any jurisdiction-specific workforce provision, the companies agree that Washington Gas would **honor all existing collective bargaining agre**ements, and **for two years after the closing**, AltaGas would provide WGL **employees compensation and benefits that are at least as favorable in the aggregate as their existing benefit packages**.

At least 65 new positions would be created within the greater Washington, D.C., metropolitan area within five years following the close of the transaction.

For ten years following the close of the merger, AltaGas would make $1.2 million in charitable contributions and traditional local community support per year in the greater Washington, D.C., metropolitan area, an approximately **20% increase over the highest of any of the past five fiscal years for WGL**.

Washington Gas' headquarters would remain in the District of Columbia. Within twelve months after closing, the **head offic**e of the **AltaGas** U.S. power business would be **relocated to within the greater Washington, D.C., metropolitan area**.

Corporate Governance Commitments

Washington Gas would have a board of directors consisting of nine members: the CEO of Washington Gas; the CEO of AltaGas; **three independent members**, including if mutually agreeable up to three of the independent board members of WGL; and four other members.

AltaGas would make reasonable efforts to retain Washington Gas' existing executive management team to manage that business and, as available, provide guidance to AltaGas' other U.S. regulated utility businesses.

Washington Gas would **maintain its standing as a separate entity from AltaGas, conduct business in its own name, and maintain separate books and records**.

Washington Gas would continue to be subject to each jurisdiction's affiliate relationships rules and existing cost-allocation policies.

Washington Gas would become a wholly owned, direct subsidiary of a **Special Purpose Entity, or SPE,** established for the **purpose of ring-fencing Washington Gas, with the intention of removing Washington Gas from the bankruptcy estate of AltaGas and its affiliates**.

A voluntary petition for bankruptcy by the SPE would require the affirmative consent of the holder of a to-be-created "Golden Share" and the unanimous vote of the SPE board of directors.

A voluntary petition for bankruptcy by Washington Gas would require the affirmative consent of the holder of the Golden Share, the unanimous vote of the SPE board of directors, and the unanimous vote of the Washington Gas board of directors.

AltaGas and Washington Gas would "**use reasonable efforts**" to **maintain Washington Gas' credit ratings at investment-grade**.

Washington Gas would refrain from paying dividends to its parent company if its senior unsecured debt is rated below investment grade by two of the three major credit rating agencies, or if, immediately after the dividend payment, its common equity level would fall below a "minimum equity ratio," defined as the weighted average of the ratemaking equity ratio for Washington Gas in its three state regulatory jurisdictions, based on the respective rate base in each jurisdiction, less five percentage points.

Washington Gas would not issue debt or equity in connection with, or to fund, the merger, and the merger would not change Washington Gas' capital structure.

Washington Gas would refrain from pledging its assets as security for any indebtedness of an affiliate or parent company, or entering into cross-default provisions involving these entities. Washington Gas would also refrain from participating in a money pool.

CASE: UE 319
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 509

Value Line (VL)
Electric Utility Profiles

Exhibits in Support
of Opening Testimony

June 16, 2017

All of the major electric utilities located in the eastern region of the United States are reviewed in this Issue; western electrics, in Issue 11; and the remaining utilities, in Issue 5.

Tax reform has been a topic of interest in many utility holding companies' fourth-quarter earnings conference calls. We discuss some potential changes, and how they would affect some companies in this industry.

Utilities are known for their generous dividends. For many companies, the first quarter is when the board of directors reviews the payout for a possible increase.

After a strong showing in 2016, most of these stocks have generally not had a notable movement in either direction in early 2017. Most of them remain expensively priced, in our view.

Tax Reform

With a new administration in the White House, the topic of tax reform is being raised. Among changes that have been unofficially proposed, one is a simple reduction in the corporate tax rate from 35% to 15%. Another is a cut to 20%; an end to the deductibility of interest expense; and treating capital expenditures as a deductible expense, instead of depreciating these assets over time. This raises additional questions—for instance, would the change to interest deductibility apply to interest on current debt or only on debt issued after the law takes effect? A separate concern for some companies is that tax incentives for renewable energy will be scaled back or even abolished. However, *NextEra Energy*, which has significant investments in wind and solar power, believes retroactive changes are unlikely to the tax laws that provided these incentives.

How would these changes affect electric utilities, their parent companies, and their nonutility affiliates? For the regulated business, it is highly likely that any effects of tax reform will be passed through to ratepayers. This is what happened some 30 years ago, following the tax changes that resulted from a 1986 law. Unfortunately, for utility holding companies as a whole, we cannot provide a better answer than "it depends." *NextEra* stated that (off a 2020 baseline), a cut to a 15% tax rate would boost earnings by $0.30-$0.40 a share. On the other hand, the other possible change would reduce profits by $0.10-$0.15 a share. *Dominion Resources* "would expect to be somewhat earnings neutral" if a tax bill is passed into law. *PPL Corporation* thinks the latter proposal we mentioned would reduce its earning power by $0.10 a share annually, but believes it could mitigate the negative effect.

Dividend Increases

Utilities have long been known for their generous dividends. This has become even more important for many investors in this era of extremely low interest rates, which provide negligible returns on cash. Many income-oriented investors focus on utility stocks because these provide attractive dividend yields. But investors don't just want dividend income, they want annual and predictable growth in the payout, as well. Accordingly, most utility stocks provide yearly growth in the disbursement, as long as this is feasible from a cash and payout-ratio standpoint.

INDUSTRY TIMELINESS: 11 (of 97)

Among the utilities covered in this Issue, *Consolidated Edison, Dominion Resources, Eversource Energy*, and *PPL* have already boosted the dividend in 2017. We think *NextEra, Public Service Enterprise Group*, and *SCANA* raised or will raise dividends shortly after this report went to press. *Duke Energy, Exelon*, and *Southern Company* will probably hike the payout later in 2017. In fact, among the 12 electric utility equities reviewed in this Issue, only *AVANGRID* and *FirstEnergy* are unlikely to increase their disbursements this year.

Many companies have a specified dividend policy, seeking to maintain an annual growth rate, a payout ratio, or both. For instance, *Eversource*'s goal is to raise the dividend by 5%-7% each year. *AVANGRID* wants to have a payout ratio in a range of 65%-75%. Its payout ratio is now well above this range, which explains why a hike in the disbursement is unlikely this year, and perhaps for a few years after that, too.

Conclusion

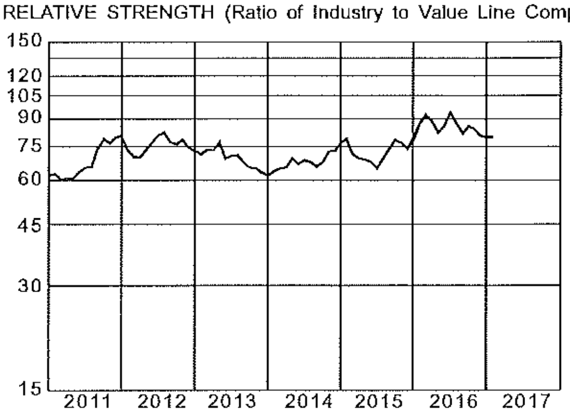
As a group, electric utility stocks had an excellent return in 2016, with a total return of 17.4%. This was a reversal from a poor showing in 2015, when the industry's total return of -3.9%. (These data were provided by the Edison Electric Institute, a trade group representing investor-owned electric companies.) So far this year, there have been few noteworthy movements in this group. One exception is *Dominion*, which lost 6% of its value at the start of February when the company's earnings guidance for 2017 was disappointing for Wall Street.

We continue to believe that most equities in this industry are expensively priced. Historically, electric utility stocks have traded at a discount to the market because utilities generally don't grow fast. Last year, however, several stocks had price-earnings ratios that were at or even above the broader market. And many of these issues have recent prices within their 2020-2022 Target Price Range. The industry's average dividend yield is 3.6%.

Paul E. Debbas, CFA

Electric Utility

RELATIVE STRENGTH (Ratio of Industry to Value Line Comp.)



Index: June, 1967 = 100

All of the major electric utilities located in the central region of the United States are reviewed in this Issue; eastern electrics, in Issue 1; and the remaining utilities, in Issue 11.

Every year, the Edison Electric Institute and Nuclear Energy Institute come to New York to make presentations before electric utility analysts. We discuss what's on the minds of these industry organizations.

In the wake of a strong showing for most electric utility stocks in 2016 and a good start in 2017, electric utility stocks remain expensively priced.

What's On EEI's Mind

Every year, usually in the second week of February, the Edison Electric Institute (EEI, a group representing investor-owned utilities) makes a presentation before electric utility analysts in New York City. EEI discusses the issues that concern its members, most of which are covered among the three Electric Utility Industry groups in Issues 1, 5, and 11.

In recent years, anything involving the electric grid has been of heightened interest to EEI, and this year's meeting was no exception. Many electric utilities are experiencing weak (if any) volume growth due to the effects of energy efficiency and sluggish economic growth. Nevertheless, capital budgets are high, and much of this spending is associated with strengthening the electric grid. Utilities are replacing parts and equipment that, in some cases, are several decades old. The grid also needs upgrading to deal with the disadvantages of renewable energy, which is intermittent and can't be dispatched. Cybersecurity and physical security are also being addressed.

With a new administration in the White House, the possibility of tax reform also has EEI's interest. A bill has not yet emerged, but rough proposals have come from the Trump Administration and the House of Representatives. Some features, such as a lower corporate tax rate and expensing of capital spending, would be positive for EEI's members. Others, such as a loss of deductibility for interest expense, would be negative. (Eventually, the regulated business would probably reflect any changes to federal tax laws, but many utility holding companies have nonregulated subsidiaries and/or debt at the parent level.) There are many moving parts to any potential legislation, and whether it would benefit each utility holding company (and to what extent) would depend on the specific company.

President Trump will also have to appoint three commissioners to fill vacancies on the five-man Federal Energy Regulatory Commission (FERC). Because FERC now lacks a quorum, it is unable to vote on matters before it. This is affecting some companies in this industry, such as *DTE Energy*, which awaits FERC approval of a proposed natural gas pipeline.

What's On NEI's Mind

Nuclear power produced 20% of the electricity supply in the United States in 2016, according to preliminary data from the U.S. Energy Information Administration. The Nuclear Energy Institute (NEI) represents the interests of nuclear plant owners in the United States. NEI and EEI have a shared interest in ensuring that nuclear plants are not shut before their license expiration dates due to economic factors. Low natural gas prices, sluggish demand for power, subsidies for renewable energy, and other factors have hurt nonregulated nuclear facilities. In 2013, Dominion Resources (covered in Issue 1) shut the Kewaunee nuclear plant in Wisconsin, and in 2014, *Entergy* closed the Vermont Yankee unit. These nonregulated merchant facilities were uneconomic in an era of low gas prices. Two nuclear plants have closed due to equipment problems, and *Entergy* plans to close three nuclear plants.

INDUSTRY TIMELINESS: 30 (of 97)

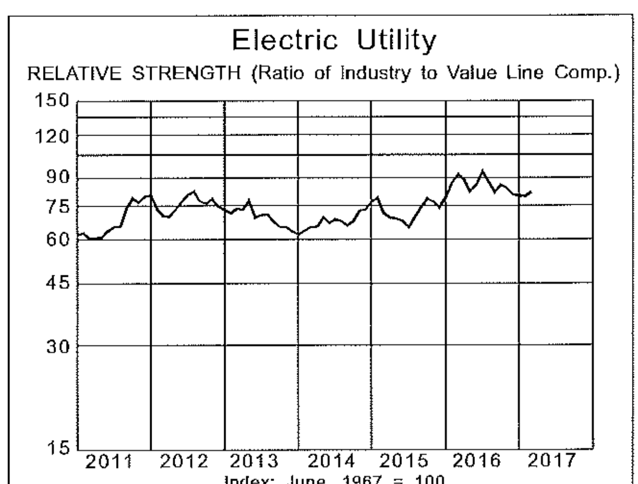
Regulatory and legislative actions in New York and Illinois, respectively, have made nuclear energy eligible for zero (pollutants) emissions credits, along with renewable energy. As a result, several plants that had been threatened with an early shutdown will stay open. (Note that there are legal challenges to the new rules in New York, and that the Indian Point station in Westchester will close anyway.) Legislative changes are being proposed in other states (Connecticut for one) that would benefit nuclear facilities.

Two utilities are building nuclear units in the Southeast. Some others have obtained construction and operating licenses for new facilities, although this doesn't necessarily mean anything will be built. Although each project has experienced delays and cost overruns, NEI believes the lessons learned will be beneficial if and when any more nuclear units are built. In addition, financing costs have been much lower than expected thanks to low interest rates. This has offset the higher construction costs.

Conclusion

In recent weeks, utility stocks have performed very well. Their valuations remain high. The average dividend yield of this industry, at 3.4%, compares favorably with the market median, but is low by historical standards. What's more, most of these equities are trading within their 3- to 5-year Target Price Range—another factor indicating that this group is not cheap. The average total return potential over that time frame is just 3%.

Paul E. Debbas, CFA



All of the major electric utilities located in the western region of the United States are reviewed in this Issue; eastern electrics, in Issue 1; and the remaining utilities, in Issue 5.

We take a look back at 2016 and a look ahead to 2017. Appointments made by the Trump Administration, and tax reform provisions that have been suggested, might well have a significant effect on the Electric Utility Industry.

We continue to believe most stocks in this group are priced expensively.

INDUSTRY TIMELINESS: 34 (of 97)

A Look Back At 2016

The year that just ended was an excellent one for most electric utility equities. In the first half, most stocks performed tremendously as interest rates declined from an already-low level and many investors sought a (relatively) safe haven in an increasingly volatile market. These issues gave back some of their first-half gains in the final six months of 2016, but the industry posted a total return of 17.4%. This topped the total return of the Standard and Poor's 500, which was 12.0%. There was a wide variance in performance among the stocks we cover in the Electric Utility Industry. Otter Tail (reviewed in Issue 5) posted a 58.9% total return. On the other hand, FirstEnergy (covered in Issue 1) was the laggard of the industry, posting a total return of just 1.9%.

Merger and acquisition activity remained vibrant last year. Among the electric utility stocks that left our coverage due to takeovers were those of Cleco, Pepco Holdings, TECO Energy, and ITC Holdings. Duke Energy, Southern Company, and Dominion Resources (all reviewed in Issue 1) completed the purchase of gas utilities. The acquisition of Empire District Electric (completed in early 2017) was announced, as was the pending merger of Great Plains Energy and Westar Energy (covered in Issue 5). Not all such activity was successful. The proposed takeover of *Hawaiian Electric Industries* by NextEra Energy was rejected by regulators in the Aloha State amidst heavy criticism.

A significant legal development happened in February of 2016 when the U.S. Supreme Court issued a stay on the Environmental Protection Agency's Clean Power Plan. The EPA's plan, designed to reduce carbon emissions and promote the use of renewable energy, is controversial due to its aggressive targets and the lack of significant support for nuclear energy, which does not emit greenhouse gases. There is also skepticism about the EPA's belief that customers' bills will decline thanks to the plan.

A Look Ahead To 2017

This month, Donald Trump was inaugurated as President of the United States. Investors should note that much regulation of the electric utility industry is conducted at the state level, and this will not change under the Trump Administration. However, changes at the federal level are likely to be significant. Mr. Trump will be able to fill two vacancies at the five-man Federal Energy Regulatory Commission, and a current commissioner's term expires in mid-2017. Even more noteworthy is a change in leadership at the EPA. The proposed new administrator, Scott Pruitt, was the attorney general in Oklahoma. In that position, Mr. Pruitt sued the EPA (unsuccessfully) about the requirements imposed on Oklahoma Gas and Electric under the Regional Haze Rule. Thus, the EPA is widely expected to take a lighter hand to regulation than it did under the Obama Administration.

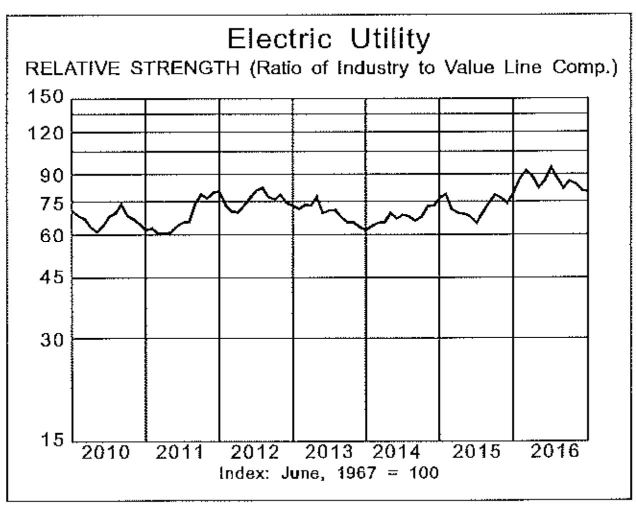
Tax reform is possible. If corporate tax rates are cut, this would not provide a windfall for the regulated utility business because companies would pass the savings through to customers. But any utility holding company with nonregulated operations would likely benefit from a reduction in tax rates. *Hawaiian Electric*, with its American Savings Bank subsidiary, is one example. On the other hand, if interest expense is no longer deductible, this would hurt this capital-intensive industry. This might well lead to a decline in merger and acquisition activity, since most deals are financed at least in part with debt.

The actions of the Federal Reserve also bear watching. In late 2016, the Fed raised interest rates. We expect further tightening this year, perhaps two or three more increases. In general, rising interest rates are bad for utility stocks that are seen as a proxy for bonds, thanks to their generous dividends. We note, though, that even after the late-2016 hike, rates are still low, and returns on cash are still negligible. This suggests that there will still be strong investor demand for stocks of dividend-paying companies such as electric utilities.

Conclusion

In early 2017, most electric utility stocks have not moved significantly. Thus, they retain their high valuation. In 2016, most traded at a price-earnings ratio in the high teens—about the same as the overall market—and the dividend yields of most issues were below 4%. These measures indicate a high valuation, by historical standards. The industry's current average dividend yield is 3.5%. Investors should note, too, that the recent quotations of some electric utility issues are near the upper end or even *above* their 2019-2021 Target Price Range. Among the utilities in this Issue that fit this description are *Hawaiian Electric, IDACORP, Avista, Pinnacle West,* and *Portland General.* Most other utility stocks are trading within this range. All told, we continue to advise caution with this group due to the high valuation of most of these equities.

Paul E. Debbas, CFA



ALLETE NYSE-ALE

RECENT PRICE 66.83 | P/E RATIO 19.7 (Trailing: 21.4 Median: 16.0) | RELATIVE P/E RATIO 1.01 | DIV'D YLD 3.2% | VALUE LINE

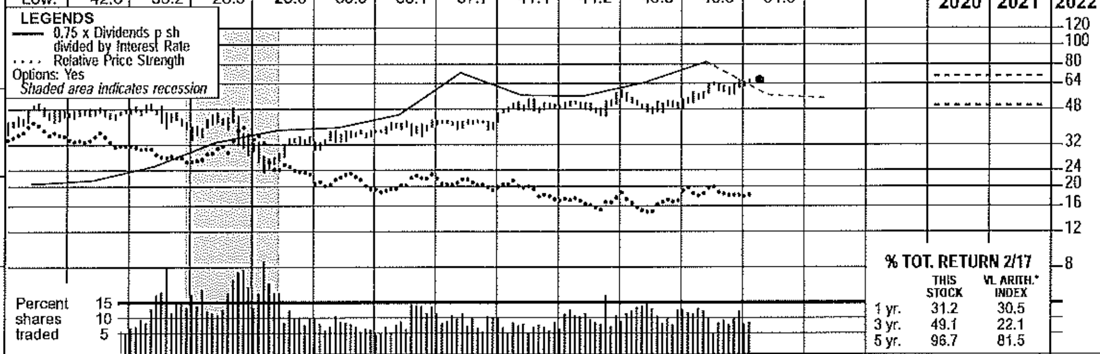
TIMELINESS 3 Lowered 9/16/16

SAFETY 2 New 10/1/04

TECHNICAL 3 Lowered 2/17/17

BETA .80 (1.00 = Market)

High:	49.3	51.3	49.0	35.3	37.9	42.5	42.7	54.1	58.0	59.7	66.9	67.8
Low:	42.6	38.2	28.3	23.3	30.0	35.1	37.7	41.4	44.2	45.3	48.3	61.6



% TOT. RETURN 2/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	31.2	30.5
3 yr.	49.1	22.1
5 yr.	96.7	81.5

2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+5%)	5%
Low	50	(-25%)	-3%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	8	0	0	0	0	0	0	8
to Sell	1	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2016	3Q2016	4Q2016
to Buy	132	129	123
to Sell	102	104	111
Hld's(000)	35449	36120	36294

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
--	--	--	25.30	24.50	25.23	27.33	24.57	21.57	25.34	24.75	24.40	24.60	24.77	30.27	27.01	*27.50*	*28.25*	Revenues per sh	*30.50*
--	--	--	2.97	3.85	4.14	4.42	4.23	3.57	4.35	4.91	5.01	5.35	5.68	6.79	7.08	*7.35*	*7.70*	"Cash Flow" per sh	*9.00*
--	--	--	1.35	2.48	2.77	3.08	2.82	1.89	2.19	2.65	2.58	2.63	2.90	3.38	3.14	*3.30*	*3.50*	Earnings per sh A	*4.00*
--	--	--	.30	1.25	1.45	1.64	1.72	1.76	1.76	1.78	1.84	1.90	1.96	2.02	2.08	*2.14*	*2.22*	Div'd Decl'd per sh B ■ †	*2.50*
--	--	--	2.12	1.95	3.37	6.82	9.24	9.05	6.95	6.38	10.30	7.93	12.48	5.84	5.35	*5.55*	*5.70*	Cap'l Spending per sh	*3.50*
--	--	--	21.23	20.03	21.90	24.11	25.37	26.41	27.26	28.78	30.48	32.44	35.06	37.07	38.17	*39.35*	*40.75*	Book Value per sh C	*45.50*
--	--	--	29.70	30.10	30.40	30.80	32.60	35.20	35.80	37.50	39.40	41.40	45.90	49.10	49.60	*50.50*	*50.80*	Common Shs Outst'g D	*52.00*
--	--	--	25.2	17.9	16.5	14.8	13.9	16.1	16.0	14.7	15.9	18.6	17.2	15.1	18.6	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*15.0*
--	--	--	1.33	.95	.89	.79	.84	1.07	1.02	.92	1.01	1.05	.91	.76	.98	*estimates*		Relative P/E Ratio	*.95*
--	--	--	.9%	2.8%	3.2%	3.6%	4.4%	5.8%	5.0%	4.6%	4.5%	3.9%	3.9%	4.0%	3.6%			Avg Ann'l Div'd Yield	*4.2%*

CAPITAL STRUCTURE as of 12/31/16
Total Debt $1558.1 mill. Due in 5 Yrs $503.6 mill.
LT Debt $1370.4 mill. LT Interest $58.9 mill.
(LT interest earned: 3.5x)
Leases, Uncapitalized Annual rentals $13.7 mill.

Pension Assets-12/16 $557.5 mill.
Oblig $743.3 mill.

Pfd Stock None

Common Stock 50,049,020 shs.
as of 2/1/17

MARKET CAP: $3.3 billion (Mid Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
841.7	801.0	759.1	907.0	928.2	961.2	1018.4	1136.8	1486.4	1339.7	*1390*	*1435*	Revenues ($mill)	*1585*
87.6	82.5	61.0	75.3	93.8	97.1	104.7	124.8	163.4	155.3	*165*	*175*	Net Profit ($mill)	*210*
34.8%	34.3%	33.7%	37.2%	27.6%	28.1%	21.5%	22.6%	19.4%	11.3%	*20.0%*	*20.0%*	Income Tax Rate	*20.0%*
6.6%	5.8%	12.8%	8.9%	2.7%	5.3%	4.4%	6.3%	2.0%	1.4%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
35.6%	41.6%	42.8%	44.2%	44.3%	43.7%	44.6%	44.2%	46.3%	42.0%	*41.5%*	*41.5%*	Long-Term Debt Ratio	*40.0%*
64.4%	58.4%	57.2%	55.8%	55.7%	56.3%	55.4%	55.8%	53.7%	58.0%	*58.5%*	*58.5%*	Common Equity Ratio	*60.0%*
1153.5	1415.4	1625.3	1747.6	1937.2	2134.6	2425.9	2882.2	3388.9	3263.4	*3405*	*3550*	Total Capital ($mill)	*3925*
1104.5	1387.3	1622.7	1805.6	1982.7	2347.6	2576.5	3286.4	3669.1	3741.2	*3815*	*3890*	Net Plant ($mill)	*3750*
8.6%	6.7%	4.8%	5.4%	6.0%	5.6%	5.3%	5.2%	5.8%	5.8%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
11.8%	10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	9.0%	8.2%	*8.5%*	*8.5%*	Return on Shr. Equity	*9.0%*
11.8%	10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	9.0%	8.2%	*8.5%*	*8.5%*	Return on Com Equity E	*9.0%*
5.8%	3.9%	.5%	1.5%	2.9%	2.3%	2.2%	2.5%	3.6%	2.8%	*3.0%*	*3.0%*	Retained to Com Eq	*3.5%*
51%	61%	93%	81%	66%	71%	72%	67%	60%	66%	*65%*	*63%*	All Div'ds to Net Prof	*62%*

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+.5	-8.9	-2.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.09	6.40	NA
Capacity at Peak (Mw)	1985	1942	NA
Peak Load, Winter (Mw)	1637	1631	1520
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	345	381	318

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	1.0%	2.5%	*2.5%*
"Cash Flow"	6.0%	9.0%	*7.0%*
Earnings	3.5%	7.0%	*5.0%*
Dividends	7.5%	2.5%	*4.0%*
Book Value	5.5%	6.0%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2014	296.5	260.7	288.9	290.7	1136.8
2015	320.0	323.3	462.5	380.6	1486.4
2016	333.8	314.8	349.6	341.5	1339.7
2017	*350*	*330*	*360*	*350*	*1390*
2018	*360*	*340*	*370*	*365*	*1435*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2014	.80	.40	.97	.73	2.90
2015	.85	.46	1.23	.83	3.38
2016	.93	.50	.81	.89	3.14
2017	*.95*	*.50*	*1.05*	*.80*	*3.30*
2018	*1.00*	*.55*	*1.10*	*.85*	*3.50*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.475	.475	.475	.475	1.90
2014	.49	.49	.49	.49	1.96
2015	.505	.505	.505	.505	2.02
2016	.52	.52	.52	.52	2.08
2017	.535				

BUSINESS: ALLETE, Inc. is the parent of Minnesota Power, which supplies electricity to 146,000 customers in northeastern MN, & Superior Water, Light & Power in northwestern WI. Electric rev. breakdown: taconite mining/processing, 26%; paper/wood products, 9%; other industrial, 8%; residential, 12%; commercial, 13%; wholesale, 16% other, 16%. ALLETE Clean Energy owns renewable energy projects. Acq'd U.S. Water Services 2/15. Has real estate operation in FL. Generating sources: coal & lignite, 49%; wind, 12%; other, 6%; purchased, 33%. Fuel costs: 25% of revs. '16 deprec. rate: 3.7%. Has 2,000 employees. Chairman, President & CEO: Alan R. Hodnik. Inc.: MN. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

ALLETE's main utility subsidiary has a rate case pending. Minnesota Power is seeking a rate hike of $39 million (6.1%), based on a return of 10.25% on a common-equity ratio of 53.8%. This is a reduction from its previous request of $55 million thanks to increased demand from the service area's mining customers. The utility is also asking for an interim rate boost of $32.2 million (5.1%). New tariffs are expected to take effect in the first half of 2018.

The company's utility in Wisconsin is still awaiting an order on its rate request. Superior Water, Light & Power is seeking an increase of $2.7 million (3.1%), based on a return of 10.9% on a common-equity ratio of 55%. New tariffs should take effect in the second quarter of 2017.

We estimate an earnings increase of 5% this year. This is in line with the company's goal of annual profit growth of at least 5%. ALLETE should benefit from rate relief, volume growth from its mining customers, and increased income from its nonutility operations, ALLETE Clean Energy and U.S. Water Services. The former is expanding a 100-megawatt wind farm by 50 mw, and the latter is gaining share of an expanding market. Between them, these two subsidiaries provided 10% of the company's net profit in 2016. Our estimate is at the midpoint of management's guidance of $3.10-$3.50 a share. We forecast 6% profit growth in 2018.

Minnesota Power has begun construction of a major transmission project. This line is expected to cost $330 million and will enable the utility to import power from Manitoba Hydro when it begins operating in 2020. It is eligible for current cost recovery, meaning that the company will earn a return on the construction work in progress.

The board of directors raised the dividend in early 2017. The increase was $0.06 a share (2.9%) annually, the same as in recent years. ALLETE is targeting a payout ratio of 60%-65%.

This stock is expensively priced. The dividend yield does not stand out among utilities. With the recent price near the upper end of our 2020-2022 Target Price Range, total return potential over that time frame is low.

Paul E. Debbas, CFA *March 17, 2017*

(A) Diluted EPS. Excl. nonrec. losses: '04, 25¢ net; '05, $1.84; '15, 46¢; gain (losses) on disc. ops.: '04, $2.57, '05, (16¢); '06, (2¢). '15 & '16 EPS don't sum due to rounding. Next earnings report due early May. (B) Div'ds historically paid in early Mar., June, Sept. and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '16: $11.55/sh. (D) In mill. (E) Rate base: Orig. cost deprec. Rate allowed on com. eq. in '10: 10.38%; earned on avg. com. eq., '16: 8.3%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	40
Earnings Predictability	90

ALLIANT ENERGY NYSE-LNT

RECENT PRICE	39.28	P/E RATIO	20.0 (Trailing: 23.8; Median: 15.0)	RELATIVE P/E RATIO	1.03	DIV'D YLD	3.2%	VALUE LINE

TIMELINESS 3 Lowered 11/18/16

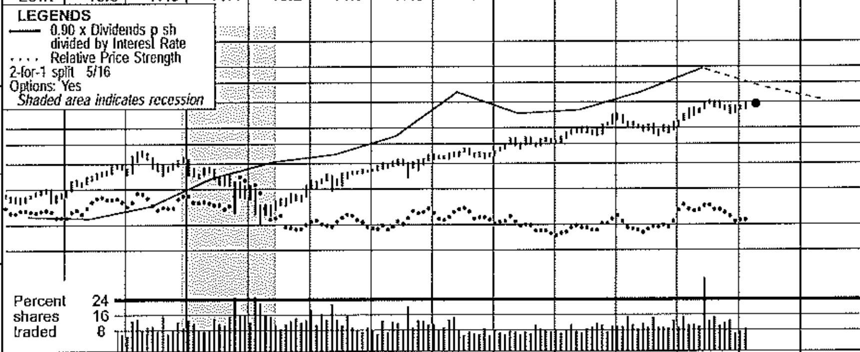
SAFETY 2 Raised 9/28/07

TECHNICAL 3 Lowered 2/17/17

BETA .70 (1.00 = Market)

High:	20.0	23.3	21.2	15.8	18.8	22.2	23.8	27.1	34.9	35.4	41.0	39.6
Low:	13.8	17.5	11.4	10.2	14.6	17.0	20.9	21.9	25.0	27.1	30.4	36.6

LEGENDS
— 0.90 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 5/16
Options: Yes
Shaded area indicates recession



Target Price Range

2020	2021	2022

2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+15%)	7%
Low	30	(-25%)	-2%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	1	0	0	0	0	0	1	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	1	1	0	0	0	0	0

Institutional Decisions

	2Q2016	3Q2016	4Q2016
to Buy	421	194	192
to Sell	47	198	196
Hld's(000)	149878	150673	152516

% TOT. RETURN 2/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	20.0	30.5
3 yr.	61.3	22.1
5 yr.	119.3	81.5

Alliant Energy, formerly called Interstate Energy Corporation, was formed on April 21, 1998 through the merger of WPL Holdings, IES Industries, and Interstate Power. WPL stockholders received one share of Interstate Energy stock for each WPL share, IES stockholders received 1.14 Interstate Energy shares for each IES share, and Interstate Power stockholders received 1.11 Interstate Energy shares for each Interstate Power share.

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
15.57	16.67	15.51	15.40	16.51	13.94	14.77	15.10	14.34	14.58	*15.20*	*15.50*	Revenues per sh	*17.15*
2.56	2.28	2.10	2.60	2.75	2.95	3.34	3.44	3.45	3.45	*4.00*	*4.15*	"Cash Flow" per sh	*5.00*
1.35	1.27	.95	1.38	1.38	1.53	1.65	1.74	1.69	1.65	*2.00*	*2.12*	Earnings per sh A	*2.50*
.64	.70	.75	.79	.85	.90	.94	1.02	1.10	1.18	*1.26*	*1.34*	Div'd Decl'd per sh B ■ †	*1.58*
2.46	3.98	5.43	3.91	3.03	5.22	3.32	3.78	4.25	5.26	*6.10*	*6.25*	Cap'l Spending per sh	*5.30*
12.15	12.78	12.54	13.05	13.57	14.12	14.79	15.54	16.41	16.96	*17.45*	*17.95*	Book Value per sh C	*19.05*
220.72	220.90	221.31	221.79	222.04	221.97	221.89	221.87	226.92	227.67	*230.00*	*232.00*	Common Shs Outst'g D	*236.00*
15.1	13.4	13.9	12.5	14.5	14.5	15.3	16.6	18.1	22.3	*Bold figures are*	*Value Line estimates*	Avg Ann'l P/E Ratio	*15.0*
.80	.81	.93	.80	.91	.92	.86	.87	.91	1.13			Relative P/E Ratio	*.95*
3.1%	4.1%	5.7%	4.6%	4.3%	4.1%	3.7%	3.5%	3.6%	3.2%			Avg Ann'l Div'd Yield	*4.2%*
3437.6	3681.7	3432.8	3416.1	3665.3	3094.5	3276.8	3350.3	3253.6	3320.0	*3500*	*3600*	Revenues ($mill)	*4050*
320.8	280.0	208.6	303.9	304.4	337.8	382.1	385.5	380.7	373.8	*460*	*490*	Net Profit ($mill)	*590*
44.4%	33.4%	--	30.1%	19.0%	21.5%	12.4%	10.1%	15.3%	13.4%	*15.0%*	*15.0%*	Income Tax Rate	*15.0%*
2.4%	--	--	--	--	--	--	6.5%	6.5%	*7.0%*	*7.0%*	*7.0%*	AFUDC % to Net Profit	*7.0%*
32.4%	36.3%	44.3%	46.3%	45.7%	48.4%	46.1%	49.7%	48.6%	*50.0%*	*50.0%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
61.9%	58.6%	51.2%	49.5%	50.9%	48.4%	50.8%	47.5%	51.4%	*48.0%*	*48.0%*	*48.0%*	Common Equity Ratio	*48.0%*
4329.5	4815.6	5423.0	5840.8	5921.2	6476.6	6461.0	7257.2	7246.3	*7600*	*7800*	*7900*	Total Capital ($mill)	*8400*
4679.9	5353.5	6203.0	6730.6	7037.1	7838.0	7147.3	6442.0	8970.2	*9700*	*10000*	*10100*	Net Plant ($mill)	*11000*
8.6%	7.0%	5.1%	6.6%	6.4%	6.3%	7.0%	5.3%	6.3%	*5.0%*	*5.0%*	*5.5%*	Return on Total Cap'l	*7.0%*
11.0%	9.1%	6.9%	9.7%	9.5%	10.1%	11.0%	10.6%	10.2%	9.7%	*11.5%*	*12.0%*	Return on Shr. Equity	*13.0%*
11.3%	9.3%	6.8%	9.9%	9.5%	10.3%	11.3%	10.9%	10.2%	9.7%	*11.5%*	*12.0%*	Return on Com Equity E	*13.0%*
5.9%	3.8%	.9%	3.8%	3.3%	3.9%	4.9%	4.3%	3.6%	2.8%	*4.0%*	*4.5%*	Retained to Com Eq	*5.0%*
50%	62%	88%	64%	67%	64%	57%	59%	65%	72%	*63%*	*63%*	All Div'ds to Net Prof	*63%*

CAPITAL STRUCTURE as of 12/31/16
Total Debt $4320.2 mill. **Due in 5 Yrs** $1500.0 mill.
LT Debt $4315.6 mill. **LT Interest** $200.0 mill.
(LT interest earned: 3.2x)

Pension Assets-12/16 $895.7 mill. **Oblig.** $1244.3 mill.

Pfd Stock $400.0 mill. **Pfd Div'd** $10.2 mill.
16,000,000 shs.

Common Stock 227,673,654 shs.
Adjusted for 2-for-1 split 4/20/16

MARKET CAP: $8.9 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+.1	-.1	+2.0
Avg. Indust. Use (MWH)	11821	11735	11987
Avg. Indust. Revs. per KWH (¢)	6.85	6.92	7.04
Capacity at Peak (Mw)	5426	5385	5615
Peak Load, Summer (Mw)	5426	5385	5615
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.4	+.3	+1.0
Fixed Charge Cov. (%)	320	325	342

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '20-'22
Revenues	1.0%	-1.5%	*4.0%*
"Cash Flow"	3.5%	8.0%	*6.0%*
Earnings	6.0%	7.0%	*6.0%*
Dividends	7.0%	6.5%	*4.5%*
Book Value	4.0%	4.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	952.8	750.3	843.1	804.1	3350.3
2015	897.4	717.2	898.9	740.1	3253.6
2016	843.8	754.2	924.6	797.4	3320.0
2017	*860*	*785*	*975*	*880*	*3500*
2018	*880*	*810*	*1005*	*905*	*3600*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.49	.28	.70	.27	1.74
2015	.44	.30	.80	.15	1.69
2016	.43	.37	.57	.28	1.65
2017	*.44*	*.36*	*.88*	*.32*	*2.00*
2018	*.47*	*.38*	*.92*	*.35*	*2.12*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.235	.235	.235	.235	.94
2014	.255	.255	.255	.255	1.02
2015	.275	.275	.275	.275	1.10
2016	.295	.295	.295	.295	1.18
2017	.315				

BUSINESS: Alliant Energy Corp., formerly named Interstate Energy, is a holding company formed through the merger of WPL Holdings, IES Industries, and Interstate Power. Supplies electricity, gas, and other services in Wisconsin, Iowa, and Minnesota. Elect. revs. by state: WI, 44%; IA, 55%; MN, 1%. Elect. rev.: residential, 35%; commercial, 25%; industrial, 29%; wholesale, 9%; other, 2%. Fuel sources, 2016: coal, 44%; gas, 21%; other, 35%. Fuel costs: 49% of revs. 2016 depreciation rate: 5.9%. Estimated plant age: 14 years. Has approximately 4,000 employees. Chairman & Chief Executive Officer: Patricia L. Kempling. Incorporated: Wisconsin. Address: 4902 N. Biltmore Lane, Madison, Wisconsin 53718. Telephone: 608-458-3311. Internet: www.alliantenergy.com.

The Public Service Commission of Wisconsin has approved a rate increase for Alliant Energy's main utility subsidiary. Electric and natural gas rates for Wisconsin Power and Light will rise by approximately $19 million in 2017 and 2018. The order was based on a return of 10% on a common-equity ratio of 52%. The utility will use the additional revenue to enhance system reliability and help pay for pollution controls at its coal-fired plants. Alliant also expects to file a rate case with the Iowa Utilities Board in the second quarter. In 2014, the IUB approved a regulatory settlement worth $105 million (paid via customer billing credits over three years) for Interstate Power and Light. With the arrangement set to expire at the end of this year, LNT will likely ask for relief in the form of rate increases to help offset the reduction in the credits.

The company has made significant progress in the field of renewable energy. At the end of 2016, Alliant was generating about 1,200 megawatts of renewable energy across three different states. The utility has plans to invest $1 billion over the next five years to expand a farm in Iowa that would add an additional 500 megawatts of wind power to its portfolio. The project is part of management's vision to reduce carbon emissions by 40% from 2005 to 2030. LNT has also pledged to ramp up investments in solar energy over the coming years as technology improves and costs come down.

The board of directors raised the dividend in January. The increase was $0.02 a share (6.8%) quarterly, as we had expected. Alliant is targeting a payout ratio in the range of 60%-70%.

Alliant increased its projected capital expenditures. The company plans to spend $5.56 billion on capex over the next four years, up from its previous outlook of $5.36 billion. The largest increase will come in 2019 when the Riverside Energy Center and Iowa wind farm expansions are completed.

This good-quality issue has a decent dividend yield and above-average growth prospects for a utility. That said, with the recent quotation well within our 2020-2022 Target Price Range, total return potential is subpar.

Daniel Henigson *March 17, 2017*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '07, 55¢; '08, 4¢; '09, (44¢); '10, (8¢); '11, (1¢); '12, (8¢). Next earnings report due early May. (B) Dividends historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. deferred chgs. In '16: $22.6 mill., $0.10/sh. (D) In millions, adjusted for split. (E) Rate base: Orig. cost. Rates all'd on com. eq. in IA in '16: 10.5%; in WI in '16 Regul. Clim.: WI, Above Avg.; IA, Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	95
Earnings Predictability	80

AMERICAN ELEC. PWR. NYSE-AEP

RECENT PRICE 66.24 | P/E RATIO 16.7 (Trailing: 15.6 / Median: 14.0) | RELATIVE P/E RATIO 0.86 | DIV'D YLD 3.7% | VALUE LINE

TIMELINESS 3 Lowered 11/11/16

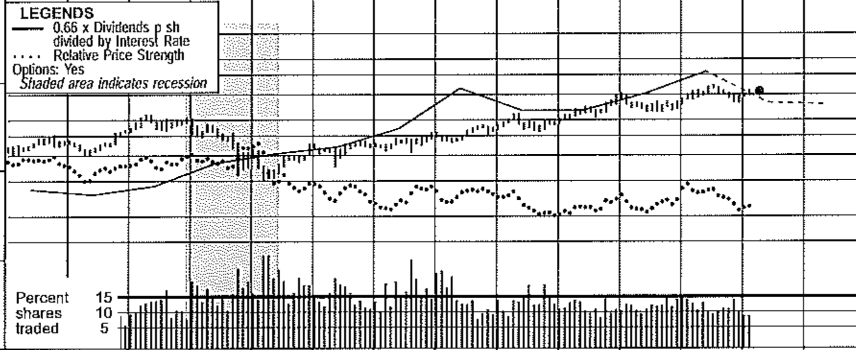
SAFETY 1 Raised 3/17/17

TECHNICAL 3 Raised 3/17/17

BETA .65 (1.00 = Market)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
High:	43.1	51.2	49.1	36.5	37.9	41.7	45.4	51.6	63.2	65.4	71.3	67.2
Low:	32.3	41.7	25.5	24.0	28.2	33.1	37.0	41.8	45.8	52.3	56.8	61.8

LEGENDS
— 0.66 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range
2020 | 2021 | 2022

2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+15%)	7%
Low	60	(-10%)	2%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	9	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2016	3Q2016	4Q2016
to Buy	389	365	389
to Sell	337	373	376
Hld's(000)	339322	333330	341984

% TOT. RETURN 2/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	12.4	30.5
3 yr.	49.1	22.1
5 yr.	116.9	81.5

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
190.10	42.96	36.82	35.51	30.76	31.82	33.41	35.56	28.22	30.01	31.27	30.77	31.48	34.78	33.51	33.31	*33.15*	*33.75*	Revenues per sh	*36.50*
7.65	6.99	5.76	5.89	5.96	6.67	6.80	6.84	6.32	6.29	6.83	6.92	7.02	7.57	7.98	8.47	*7.95*	*8.25*	"Cash Flow" per sh	*9.50*
3.27	2.86	2.53	2.61	2.64	2.86	2.86	2.99	2.97	2.60	3.13	2.98	3.18	3.34	3.59	4.23	*3.65*	*3.85*	Earnings per sh A	*4.75*
2.40	2.40	1.65	1.40	1.42	1.50	1.58	1.64	1.64	1.71	1.85	1.88	1.95	2.03	2.15	2.27	*2.39*	*2.51*	Div'd Decl'd per sh B ■	*2.90*
5.69	5.08	3.44	4.28	6.11	8.89	8.88	9.83	6.19	5.07	5.74	6.45	7.75	8.68	9.37	9.98	*11.90*	*12.65*	Cap'l Spending per sh	*12.50*
25.54	20.85	19.93	21.32	23.08	23.73	25.17	26.33	27.49	28.33	30.33	31.37	32.98	34.37	36.44	35.38	*36.90*	*38.25*	Book Value per sh C	*43.25*
322.24	338.84	395.02	395.86	393.72	396.67	400.43	406.07	478.05	480.81	483.42	485.67	487.78	489.40	491.05	491.71	*492.00*	*492.00*	Common Shs Outst'g D	*492.00*
13.9	12.7	10.7	12.4	13.7	12.9	16.3	13.1	10.0	13.4	11.9	13.8	14.5	15.9	15.8	15.2	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
.71	.69	.61	.66	.73	.70	.87	.79	.67	.85	.75	.88	.81	.84	.80	.80	*Value Line*		Relative P/E Ratio	*.90*
5.3%	6.6%	6.1%	4.3%	3.9%	4.1%	3.4%	4.2%	5.5%	4.9%	5.0%	4.6%	4.2%	3.8%	3.8%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*

CAPITAL STRUCTURE as of 12/31/16
Total Debt $21969 mill. **Due in 5 Yrs** $10660 mill.
LT Debt $17378 mill. **LT Interest** $782 mill.
Incl. $1728 mill. securitized bonds. Incl. $343.5 mill. capitalized leases.
(LT interest earned: 4.1x)
Leases, Uncapitalized Annual rentals $238.2 mill.
Pension Assets-12/16 $4827.3 mill.
Oblig $5085.8 mill.

Pfd Stock None

Common Stock 491,711,928 shs.

MARKET CAP: $33 billion (Large Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
13380	14440	13489	14427	15116	14945	15357	17020	16453	16380	*16300*	*16600*	Revenues ($mill)	*18000*
1147.0	1208.0	1365.0	1248.0	1513.0	1443.0	1549.0	1634.0	1763.4	2073.6	*1735*	*1835*	Net Profit ($mill)	*2250*
31.1%	31.3%	29.7%	34.8%	31.7%	33.9%	36.2%	37.8%	35.1%	26.8%	*36.0%*	*36.0%*	Income Tax Rate	*36.0%*
9.8%	9.9%	10.9%	10.4%	10.6%	11.2%	7.3%	9.0%	11.0%	8.0%	*12.0%*	*12.0%*	AFUDC % to Net Profit	*9.0%*
58.3%	59.1%	54.4%	53.1%	50.7%	50.6%	51.1%	49.0%	49.8%	50.0%	*52.0%*	*52.0%*	Long-Term Debt Ratio	*52.5%*
41.4%	40.7%	45.4%	46.7%	49.3%	49.4%	48.9%	51.0%	50.2%	50.0%	*48.0%*	*48.0%*	Common Equity Ratio	*47.5%*
24342	26290	28956	29184	29747	30823	32913	33001	35633	34775	*37675*	*39250*	Total Capital ($mill)	*44800*
29870	32987	34344	35674	36971	38763	40997	44117	46133	45639	*49375*	*53450*	Net Plant ($mill)	*64600*
6.3%	6.2%	6.2%	5.7%	6.6%	6.1%	6.0%	6.3%	6.1%	7.2%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
11.3%	11.2%	10.3%	9.1%	10.3%	9.5%	9.6%	9.7%	9.9%	11.9%	*9.5%*	*10.0%*	Return on Shr. Equity	*10.5%*
11.4%	11.3%	10.4%	9.1%	10.3%	9.5%	9.6%	9.7%	9.9%	11.9%	*10.0%*	*10.0%*	Return on Com Equity E	*11.0%*
5.1%	5.1%	4.6%	3.1%	4.2%	3.5%	3.7%	3.8%	3.9%	5.5%	*3.5%*	*3.5%*	Retained to Com Eq	*4.5%*
55%	55%	56%	66%	60%	63%	62%	61%	60%	54%	*68%*	*67%*	All Div'ds to Net Prof	*63%*

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+1.1	-1.2	+.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	+.3	NA
Fixed Charge Cov. (%)	348	356	374

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	.5%	2.5%	*1.5%*
"Cash Flow"	2.5%	4.5%	*3.0%*
Earnings	3.0%	5.0%	*4.0%*
Dividends	4.0%	4.5%	*5.0%*
Book Value	4.5%	4.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	4648	4044	4302	4026	17020
2015	4580	3827	4431	3615	16453
2016	4045	3893	4652	3790	16380
2017	*4100*	*3900*	*4500*	*3800*	*16300*
2018	*4250*	*3950*	*4550*	*3850*	*16600*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	1.15	.80	1.01	.39	3.34
2015	1.27	.88	1.04	.41	3.59
2016	1.02	1.03	1.43	.76	4.23
2017	*1.15*	*.90*	*1.15*	*.45*	*3.65*
2018	*1.25*	*.95*	*1.20*	*.45*	*3.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.47	.49	.49	.50	1.95
2014	.50	.50	.50	.53	2.03
2015	.53	.53	.53	.56	2.15
2016	.56	.56	.56	.59	2.27
2017	.59				

BUSINESS: American Electric Power Company, Inc. (AEP), through 10 operating utilities, serves 5.4 mill. customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, & West Virginia. Electric revenue breakdown: residential, 40%; commercial, 23%; industrial, 19%; wholesale, 15%; other, 3%. Sold SEEBOARD (British utility) '02; Houston Pipeline '05; commercial barge operation in '15. Generating sources not available. Fuel costs: 35% of revenues. '16 reported deprec. rates (utility): 1.5%-8.6%. Has 17,400 employees. Chairman, President & CEO: Nicholas K. Akins. Incorporated: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Tel.: 614-716-1000. Internet: www.aep.com.

American Electric Power has completed an asset sale. In recent years, low power prices and sluggish demand for electricity have hurt the nonregulated power-generating business. AEP wants to exit this segment, and took a step in this direction by selling 5,200 megawatts of coal- and gas-fired assets. Net proceeds of the transaction are $1.2 billion, which the company will use to invest in its regulated utilities (especially electric transmission) and its nascent renewable-energy business. AEP expects to record a nonrecurring aftertax gain of $130 million in the March quarter.

We have raised the company's Financial Strength rating and the stock's Safety rank. This reflects AEP's lower risk as it exits the nonregulated generating business. We lifted the company's Financial Strength rating from A to A+ and the equity's Safety grade from 2 to 1 (Highest).

Investors should not be alarmed by the earnings decline we estimate in 2017. The aforementioned asset sale is understandable strategically, and will reduce AEP's risks, but will hurt ongoing profits by more than $0.30 a share this year. We assume no recurrence of the favorable weather conditions that helped the company in 2016. We have reduced our earnings estimate by $0.30 a share, to $3.65. This is the midpoint of AEP's targeted range of $3.55-$3.75 a share.

Profit growth should resume in 2018. AEP should benefit from some rate relief (see below) and ongoing investment in electric transmission. Our earnings estimate of $3.85 a share (again, the midpoint of the company's guidance of $3.75-$3.95) would produce an increase within management's annual goal of 5%-7%.

A rate case is pending in Texas. SWEPCO filed for an increase of $106 million (including monies already being recovered through various regulatory mechanisms), based on a 10% return on a 51.54% common-equity ratio. AEP's utilities in Oklahoma and Kentucky expect to file rate applications this year.

We consider this stock fairly valued. The dividend yield and 3- to 5-year total return potential are close to the averages for electric companies.

Paul E. Debbas, CFA *March 17, 2017*

(A) Dil. EPS. Excl. nonrec. gains (losses): '03, ($1.92); '04, 24¢; '05, (62¢); '06, (20¢); '07, (20¢); '08, 40¢; '10, (7¢); '11, 89¢; '12, (38¢); '13, (14¢); '16, ($2.99); 1Q '17, 26¢; disc. ops.: '03, (32¢); '04, 15¢; '05, 7¢; '06, 2¢; '08, 3¢; '15, 58¢; '16, (1¢). '14-'16 EPS don't sum due to rounding. Next egs. report due late Apr. (B) Div'ds paid early Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '16: $15.79/sh. (D) In mill. (E) Rate base: various. Rates all'd on com. eq.: 9.65%-10.9%; earn. on avg. com. eq., '16: 11.3%. Regul. Climate: Avg.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	90

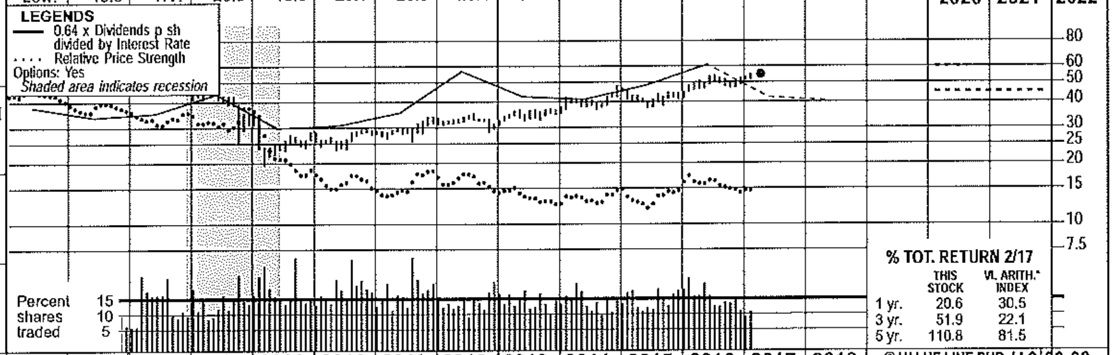
AMEREN NYSE-AEE

RECENT PRICE 54.82 | P/E RATIO 20.1 (Trailing: 20.4 / Median: 15.0) | RELATIVE P/E RATIO 1.03 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS 3 Lowered 8/19/16
SAFETY 2 Raised 6/20/14
TECHNICAL 4 Lowered 3/17/17
BETA .70 (1.00 = Market)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
High:	55.2	55.0	54.3	35.3	29.9	34.1	35.3	37.3	48.1	46.8	54.1	55.5
Low:	48.0	47.1	25.5	19.5	23.1	25.5	28.4	30.6	35.2	37.3	41.5	51.4

LEGENDS
— 0.64 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2020 | 2021 | 2022

2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+10%)	6%
Low	45	(-20%)	-1%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	10
to Sell	0	2	0	1	1	0	1	0	1

Institutional Decisions

	2Q2016	3Q2016	4Q2016
to Buy	246	200	222
to Sell	166	205	228
Hld's(000)	162780	162586	169889

% TOT. RETURN 2/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	20.6	30.5
3 yr.	51.9	22.1
5 yr.	110.8	81.5

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
32.64	24.93	28.20	26.43	33.12	33.30	36.23	36.92	29.87	31.77	31.04	28.14	24.06	24.95	25.13	25.04	*25.75*	*26.60*	Revenues per sh	*29.00*
6.33	5.28	6.29	5.57	6.10	6.02	6.76	6.44	6.06	6.33	5.87	5.87	5.25	5.77	6.08	6.59	*7.05*	*7.55*	"Cash Flow" per sh	*9.25*
3.41	2.66	3.14	2.82	3.13	2.66	2.98	2.88	2.78	2.77	2.47	2.41	2.10	2.40	2.38	2.68	*2.80*	*3.00*	Earnings per sh A	*3.50*
2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	1.54	1.54	1.56	1.60	1.60	1.61	1.66	1.72	*1.78*	*1.84*	Div'd Decl'd per sh B ■	*2.15*
7.99	5.11	4.19	4.13	4.63	4.99	6.96	9.75	7.51	4.66	4.50	5.49	5.87	7.66	8.12	8.78	*9.15*	*9.30*	Cap'l Spending per sh	*9.75*
24.26	24.93	26.73	29.71	31.09	31.86	32.41	32.80	33.08	32.15	32.64	27.27	26.97	27.67	28.63	29.27	*30.30*	*31.50*	Book Value per sh C	*35.50*
138.05	154.10	162.90	195.20	204.70	206.60	208.30	212.30	237.40	240.40	242.60	242.63	242.63	242.63	242.63	242.63	*242.63*	*242.63*	Common Shs Outst'g D	*242.63*
12.1	15.8	13.5	16.3	16.7	19.4	17.4	14.2	9.3	9.7	11.9	13.4	16.5	16.7	17.5	18.3	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
.62	.86	.77	.86	.89	1.05	.92	.85	.62	.62	.75	.85	.93	.88	.88	.96	*Value Line*		Relative P/E Ratio	*.90*
6.2%	6.1%	6.0%	5.5%	4.9%	4.9%	4.9%	6.2%	6.0%	5.8%	5.3%	5.0%	4.6%	4.0%	4.0%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*

CAPITAL STRUCTURE as of 12/31/16
Total Debt $7834 mill. Due in 5 Yrs $3110 mill.
LT Debt $6595 mill. LT Interest $330 mill.
(LT interest earned: 4.0x)
Leases, Uncapitalized Annual rentals $6 mill.
Pension Assets-12/16 $3813 mill. Oblig $4518 mill.
Pfd Stock $142 mill. Pfd Div'd $6 mill.
807,595 sh. $3.50 to $5.50 cum. (no par), $100 stated val., redeem. $102.176-$110/sh.; 616,323 sh. 4.00% to 6.625%, $100 par, redeem. $100-$104/sh.
Common Stock 242,634,798 shs. as of 1/31/17
MARKET CAP: $13 billion (Large Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
7546.0	7839.0	7090.0	7638.0	7531.0	6828.0	5838.0	6053.0	6098.0	6076.0	*6250*	*6450*	Revenues ($mill)	*7050*
629.0	615.0	624.0	669.0	602.0	589.0	518.0	593.0	585.0	659.0	*690*	*740*	Net Profit ($mill)	*865*
33.5%	33.7%	34.7%	36.8%	37.3%	36.9%	37.5%	38.9%	38.3%	36.7%	*38.0%*	*38.0%*	Income Tax Rate	*38.0%*
.8%	4.6%	5.8%	7.8%	5.6%	6.1%	7.1%	5.7%	5.1%	4.1%	*4.0%*	*4.0%*	AFUDC % to Net Profit	*3.0%*
45.0%	47.8%	49.7%	48.2%	45.3%	49.5%	45.2%	47.2%	49.3%	47.7%	*47.5%*	*48.0%*	Long-Term Debt Ratio	*48.5%*
53.4%	50.8%	49.1%	50.9%	53.7%	49.4%	53.7%	51.7%	49.7%	51.3%	*51.5%*	*51.0%*	Common Equity Ratio	*50.5%*
12654	13712	15991	15185	14738	13384	12190	12975	13968	13840	*14250*	*14975*	Total Capital ($mill)	*17000*
15069	16567	17610	17853	18127	16096	16205	17424	18799	20113	*21325*	*22475*	Net Plant ($mill)	*25700*
6.2%	5.7%	5.3%	6.0%	5.6%	6.0%	5.6%	5.8%	5.3%	6.0%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
9.0%	8.6%	7.8%	8.5%	7.5%	8.7%	7.7%	8.7%	8.3%	9.1%	*9.0%*	*9.5%*	Return on Shr. Equity	*10.0%*
9.2%	8.7%	7.8%	8.6%	7.5%	8.8%	7.8%	8.7%	8.3%	9.2%	*9.5%*	*9.5%*	Return on Com Equity E	*10.0%*
1.3%	1.0%	3.5%	3.8%	2.8%	3.0%	1.9%	2.9%	2.5%	3.3%	*3.5%*	*4.0%*	Retained to Com Eq	*4.0%*
86%	88%	56%	56%	63%	66%	76%	67%	70%	64%	*63%*	*61%*	All Div'ds to Net Prof	*61%*

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	-.1	-1.1	-4.2
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.46	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	355	343	351

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	-2.0%	-4.0%	2.5%
"Cash Flow"	.5%	--	7.0%
Earnings	-1.5%	-1.5%	6.0%
Dividends	-4.0%	1.5%	4.5%
Book Value	-1.0%	-2.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	1594	1419	1670	1370	6053.0
2015	1556	1401	1833	1308	6098.0
2016	1434	1427	1859	1356	6076.0
2017	*1500*	*1450*	*1900*	*1400*	*6250*
2018	*1550*	*1500*	*1950*	*1450*	*6450*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.40	.62	1.20	.19	2.40
2015	.45	.40	1.41	.12	2.38
2016	.43	.61	1.52	.13	2.68
2017	*.45*	*.65*	*1.50*	*.20*	*2.80*
2018	*.50*	*.70*	*1.55*	*.25*	*3.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.40	.40	.40	.40	1.60
2014	.40	.40	.40	.41	1.61
2015	.41	.41	.41	.425	1.66
2016	.425	.425	.425	.44	1.72
2017					

BUSINESS: Ameren Corporation is a holding company formed through the merger of Union Electric and CIPSCO. Acq'd CILCORP 1/03; Illinois Power 10/04. Has 1.2 mill. electric and 127,000 gas customers in Missouri; 1.2 mill. electric and 813,000 gas customers in Illinois. Discontinued nonregulated power-generation operation in '13. Electric rev. breakdown: residential, 45%; commercial, 33%; industrial, 12%; other, 10%. Generating sources: coal, 66%; nuclear, 23%; hydro, 3%; purchased & other, 8%. Fuel costs: 28% of revs. '16 reported deprec. rates: 3%-4%. Has 8,600 employees. Chairman, President & CEO: Warner L. Baxter. Inc.: MO. Address: One Ameren Plaza, 1901 Chouteau Ave., P.O. Box 66149, St. Louis, MO 63166-6149. Tel.: 314-621-3222. Internet: www.ameren.com.

Ameren has reached a settlement of its electric rate case in Missouri. The agreement, if approved by the Missouri commission, would raise rates by $92 million. It would also remove the negative effect of a reduction in electric sales to an aluminum smelter. Certain regulatory tracking mechanisms would continue. This is a "black box" settlement in which an allowed return on equity and common-equity ratio are not specified. The agreement calls for new tariffs to take effect no later than March 20, 2017.

We estimate that earnings will advance nearly 5% in 2017. The earnings comparison is made tougher by the favorable weather conditions that boosted profits by $0.08 a share in 2016. We assume normal weather conditions in our estimates. Ameren should benefit from a partial year of rate relief in Missouri. In addition, its operations in Illinois and its federally regulated transmission business have forward-looking rate plans that lift the company's earning power each year. Our earnings estimate of $2.80 a share is within Ameren's guidance of $2.65-$2.85.

We forecast further profit growth in 2018. Ameren will have a full year's worth of the rate hike in Missouri and additional revenues from the formula rate plans. In addition, there will be no refueling outage for the Callaway nuclear unit next year. Our $3.00-a-share earnings estimate would produce a growth rate within Ameren's goal of 5%-8% annually.

The regulatory structure in Missouri isn't as supportive as that in Illinois and that of the Federal Energy Regulatory Commission (FERC). This is why Ameren is directing the majority of its capital spending toward its Illinois utilities and its FERC-regulated electric transmission business. Missouri uses a historical test year, which results in regulatory lag for the state's utilities. Legislative action is being sought to improve this situation, but similar efforts in recent years have been unsuccessful.

Neither the dividend yield of Ameren stock nor its 3- to 5-year total return potential stand out among utility issues. Like many utility equities, the recent quotation is well within our 2020-2022 Target Price Range.

Paul E. Debbas, CFA *March 17, 2017*

(A) Diluted EPS. Excl. nonrecur. gain (losses): '05, (11¢); '10, ($2.19); '11, (32¢); '12, ($6.42); gain (loss) from disc. ops.: '13, (92¢); '15, 21¢. '14 & '16 EPS don't sum due to rounding. Next egs. report due early May. (B) Div'ds histor. paid in late Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '16: $7.62/sh. (D) In mill. (E) Rate base: Orig. cost depr. Rate all'd on com. eq. in MO in '15: elec., 9.53%; in '11: gas, none specified; in IL in '14: elec., 8.7%, in '16: gas, 9.6%; earned on avg. com. eq., '16: 9.3%. Reg. Climate: Below Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	25
Earnings Predictability	85

AVISTA CORP. NYSE-AVA

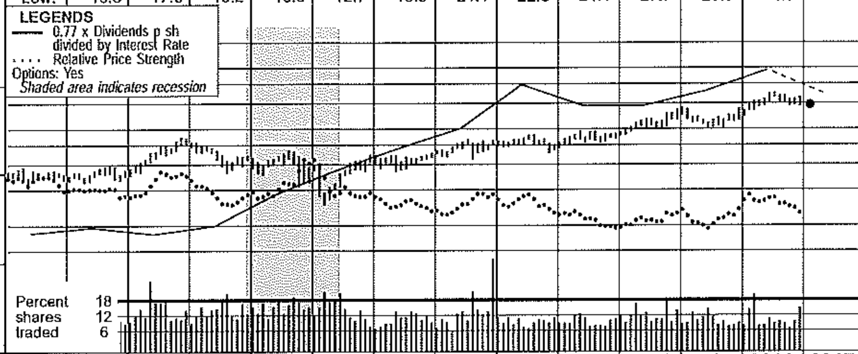
RECENT PRICE 39.43 | P/E RATIO 19.9 (Trailing: 19.2; Median: 16.0) | RELATIVE P/E RATIO 1.01 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS **3** Raised 12/30/16
SAFETY **2** Raised 5/7/10
TECHNICAL **2** Raised 1/20/17
BETA .70 (1.00 = Market)

High:	20.2	27.5	25.8	23.6	22.4	22.8	26.5	28.0	29.3	37.4	38.3	45.2
Low:	16.3	17.6	18.2	15.5	12.7	18.5	21.1	22.8	24.1	27.7	29.8	34.3

Target Price Range
2019 | 2020 | 2021

LEGENDS
—— 0.77 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(Nil)	4%
Low	30	(-25%)	-2%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	8	0	0	1	9	0	0
to Sell	4	0	6	4	0	2	1	0	0

Institutional Decisions

	1Q2016	2Q2016	3Q2016
to Buy	139	118	119
to Sell	84	104	101
Hld's(000)	42375	43564	44354

Percent shares traded 18 12 6

% TOT. RETURN 12/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	17.0	20.7
3 yr.	59.1	20.2
5 yr.	90.8	95.2

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
167.59	126.17	20.41	23.24	23.76	27.98	28.68	26.80	30.77	27.58	27.29	27.73	25.86	26.94	23.66	23.83	*22.10*	*21.90*	Revenues per sh	*23.75*
3.31	2.71	2.19	2.63	2.35	2.72	4.27	2.93	3.98	4.45	3.62	3.78	3.70	4.36	4.36	4.92	*4.90*	*5.00*	"Cash Flow" per sh	*5.75*
1.76	1.20	.67	1.02	.73	.92	1.47	.72	1.36	1.58	1.65	1.72	1.32	1.85	1.84	1.89	*2.05*	*1.95*	Earnings per sh A	*2.25*
.48	.48	.48	.49	.52	.55	.57	.60	.69	.81	1.00	1.10	1.16	1.22	1.27	1.32	1.37	*1.37*	Div'd Decl'd per sh B ▪	*1.50*
4.24	5.92	1.74	2.21	2.47	3.23	3.14	4.04	4.09	3.86	3.64	4.20	4.61	5.05	5.47	6.46	*6.25*	*6.60*	Cap'l Spending per sh	*6.75*
15.34	15.12	14.84	15.54	15.54	15.87	17.46	17.27	18.30	19.17	19.71	20.30	21.06	21.61	23.84	24.53	*25.55*	*26.10*	Book Value per sh C	*28.00*
47.21	47.63	48.04	48.34	48.47	48.59	52.51	52.91	54.49	54.84	57.12	58.42	59.81	60.08	62.24	62.31	*64.50*	*65.00*	Common Shs Outst'g D	*66.50*
13.6	13.7	19.3	13.8	24.4	19.4	15.4	30.9	15.0	11.4	12.7	14.1	19.3	14.6	17.3	17.6	*19.7*		Avg Ann'l P/E Ratio	*15.5*
.88	.70	1.05	.79	1.29	1.03	.83	1.64	.90	.76	.81	.88	1.23	.82	.91	.89	*1.05*		Relative P/E Ratio	*.95*
2.0%	2.9%	3.7%	3.5%	2.9%	3.0%	2.5%	2.7%	3.4%	4.5%	4.8%	4.5%	4.6%	4.5%	4.0%	4.0%	3.4%		Avg Ann'l Div'd Yield	*4.3%*

CAPITAL STRUCTURE as of 9/30/16
Total Debt $1817.1 mill. **Due in 5 Yrs** $606.7 mill.
LT Debt $1729.8 mill. **LT Interest** $83.9 mill.
Incl. $51.5 mill. debt to affiliated trusts.
(LT interest earned: 3.4x)

Pension Assets-12/15 $517.2 mill.
Oblig. $613.5 mill.

Pfd Stock None

Common Stock 64,184,399 shs.
as of 10/28/16

MARKET CAP: $2.5 billion (Mid Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
1506.3	1417.8	1676.8	1512.6	1558.7	1619.8	1547.0	1618.5	1472.6	1484.8	*1425*	*1425*	Revenues ($mill)	*1575*
75.1	38.5	73.6	87.1	92.4	100.2	78.2	111.1	114.2	118.1	*130*	*130*	Net Profit ($mill)	*145*
35.9%	38.7%	38.3%	34.3%	35.0%	35.4%	34.4%	36.0%	37.6%	36.3%	*36.5%*	*36.5%*	Income Tax Rate	*36.5%*
3.9%	22.4%	14.0%	4.2%	4.0%	5.2%	8.3%	8.8%	11.1%	10.1%	*9.0%*	*9.0%*	AFUDC % to Net Profit	*8.0%*
53.7%	41.0%	48.1%	50.9%	51.6%	51.4%	50.8%	51.4%	51.0%	50.0%	*51.0%*	*48.5%*	Long-Term Debt Ratio	*51.0%*
46.3%	59.0%	51.9%	49.1%	48.4%	48.6%	49.2%	48.6%	49.0%	50.0%	*49.0%*	*51.5%*	Common Equity Ratio	*49.0%*
1980.1	1548.9	1919.5	2139.0	2325.3	2439.9	2561.2	2669.7	3027.3	3060.3	*3355*	*3280*	Total Capital ($mill)	*3775*
2215.0	2351.3	2492.2	2607.0	2714.2	2860.8	3023.7	3202.4	3620.0	3898.6	*4115*	*4350*	Net Plant ($mill)	*5000*
6.1%	5.2%	5.8%	5.5%	5.4%	5.5%	4.3%	5.4%	4.9%	5.1%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.0%*
8.2%	4.2%	7.4%	8.3%	8.2%	8.5%	6.2%	8.6%	7.7%	7.7%	*8.0%*	*7.5%*	Return on Shr. Equity	*8.0%*
8.0%	4.2%	7.4%	8.3%	8.2%	8.5%	6.2%	8.6%	7.7%	7.7%	*8.0%*	*7.5%*	Return on Com Equity E	*8.0%*
4.9%	.8%	3.7%	4.1%	3.3%	3.1%	.8%	2.9%	2.4%	2.3%	*2.5%*	*2.5%*	Retained to Com Eq	*2.5%*
40%	82%	50%	51%	60%	64%	88%	66%	69%	70%	*67%*	*69%*	All Div'ds to Net Prof	*69%*

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	+.4	+.8	-2.0
Avg. Indust. Use (MWH)	1428	1349	1339
Avg. Indust. Revs. per KWH (¢)	5.74	5.93	6.17
Capacity at Peak (Mw)	2767	2594	NA
Peak Load, Winter (Mw)	2223	2223	NA
Annual Load Factor (%)	59.0	64.0	NA
% Change Customers (yr-end)	+1.1	+5.5	+1.3
Fixed Charge Cov. (%)	308	322	315

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	--	-3.0%	*-.5%*
"Cash Flow"	6.0%	2.5%	*4.0%*
Earnings	7.5%	4.0%	*3.0%*
Dividends	9.5%	9.0%	*3.0%*
Book Value	4.0%	4.0%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	482.9	352.0	335.9	447.7	1618.5
2014	446.6	312.6	301.6	411.8	1472.6
2015	446.5	337.3	313.7	387.3	1484.8
2016	418.2	318.8	303.3	*384.7*	*1425*
2017	*420*	*315*	*305*	*385*	*1425*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.71	.43	.19	.53	1.85
2014	.79	.43	.16	.48	1.84
2015	.74	.40	.21	.54	1.89
2016	.89	.43	.19	*.54*	*2.05*
2017	*.85*	*.40*	*.15*	*.55*	*1.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B ▪ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.305	.305	.305	.305	1.22
2014	.3175	.3175	.3175	.3175	1.27
2015	.33	.33	.33	.33	1.32
2016	.3425	.3425	.3425	.3425	1.37
2017					

BUSINESS: Avista Corporation (formerly The Washington Water Power Company) supplies electricity & gas in eastern Washington & northern Idaho. Supplies electricity to part of Alaska & gas to part of Oregon. Customers: 392,000 electric, 335,000 gas. Acq'd Alaska Electric Light and Power 7/14. Sold Ecova energy-management sub. 6/14. Electric rev. breakdown: residential, 34%; commercial, 31%; industrial, 11%; wholesale, 13%; other, 11%. Generating sources: gas & coal, 32%; hydro, 28%; purchased, 40%. Fuel costs: 44% of revs. '15 reported deprec. rate (Avista): 3.1%. Has 1,900 employees. Chairman, President & CEO: Scott L. Morris. Inc.: WA. Address: 1411 E. Mission Ave., Spokane, WA 99202-2600. Tel.: 509-489-0500. Web: www.avistacorp.com.

Avista was "extremely disappointed" by the rate decision it received in Washington in December. That is how management described the order from the Washington Utilities and Transportation Commission (WUTC), which denied the utility's request for electric and gas rate increases. Avista had filed for electric and gas tariff hikes for 2017 of $38.6 million and $4.4 million, respectively, followed by smaller increases at the start of 2018. The WUTC's ruling was surprising, given that its staff had recommended raises of $25.6 million for electricity and $2.1 million for gas. The company has asked the WUTC for reconsideration and a rehearing. If this is fruitless, Avista may appeal this matter to the courts.

The lack of rate relief in Washington will hurt 2017 earnings by an estimated $0.20-$0.30 a share. We have lowered our estimate by $0.20 a share, to $1.95. We will adjust our estimate if Avista winds up getting some rate relief in Washington.

Will this affect the board's decision about the dividend? In recent years, the directors have raised the disbursement in the first quarter. We now estimate no dividend hike due to the regulatory problems, but we don't rule one out.

Avista was granted an electric rate increase in Idaho. The raise was $6.3 million (2.5%), based on a 9.5% return on a 50% common-equity ratio. New tariffs took effect at the start of 2017.

Rate cases are pending in Alaska and Oregon. Alaska Electric Light & Power filed for an increase of $2.8 million (8.1%), based on a 13.8% return on a 58% common-equity ratio. (The cost-of-capital figures are high due to the utility's risks of operating in Juneau.) An interim hike of $1.3 million (3.9%) took effect on November 23rd. The final order is expected in late 2017. In Oregon, Avista is seeking a gas rate boost of $8.5 million (9%), based on a 9.9% return on a 50% common-equity ratio. New tariffs are expected to take effect on October 1st.

We think this stock lacks investor appeal. The recent price does not adequately reflect the regulatory uncertainty, in our view. Moreover, 3- to 5-year total return potential is low.

Paul E. Debbas, CFA *January 27, 2017*

(A) Dil. EPS. Excl. nonrec. gain (losses): '02, (9¢); '03, (3¢); '14, 9¢; gains (losses) on disc. ops.: '01, ($1.00); '02, 2¢; '03, (10¢); '14, $1.17; '16, 8¢. '13 & '14 EPS don't add due to rounding or change in shs. Next earnings report due late Feb. (B) Div'ds paid in mid-Mar., June, Sept. & Dec. ▪ Div'd reinv. avail. (C) Incl. def'd chgs. In '15: $9.89/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in WA in '16: 9.5%; in ID in '17: 9.5%; in OR in '15: 9.5%; earn. on avg. com. eq., '15: 8.2%. Regul. Clim.: WA, Avg.; ID, Above Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	75

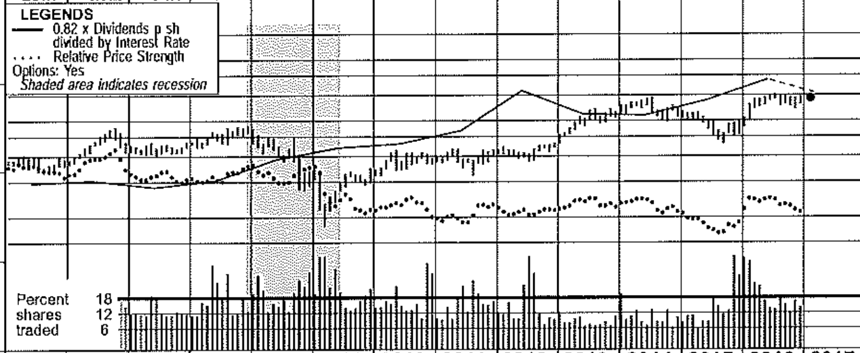
BLACK HILLS CORP. NYSE-BKH

RECENT PRICE	61.73	P/E RATIO	19.0 (Trailing: 27.0; Median: 17.0)	RELATIVE P/E RATIO	0.96	DIV'D YLD	3.0%	VALUE LINE

TIMELINESS 3 Lowered 9/16/16
SAFETY 2 Raised 5/1/15
TECHNICAL 3 Lowered 12/23/16
BETA .90 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	44.6	37.9	45.4	44.0	28.0	34.5	34.8	37.0	55.1	62.1	53.4	64.6
Low:	29.2	32.5	35.4	21.7	14.5	25.7	25.8	30.3	36.9	47.1	36.8	44.7

LEGENDS
— 0.82 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range
2019 | 2020 | 2021
128
96
80
64
48
40
32
24
16
12

2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+15%)	*6%*
Low	55	(-10%)	*1%*

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	10	4	4	8	4	4	8	5	5
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2016	2Q2016	3Q2016
to Buy	144	135	118
to Sell	92	99	114
Hld's(000)	45952	46685	48357

Percent shares traded 18 12 6

% TOT. RETURN 12/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	36.1	20.7
3 yr.	28.3	20.2
5 yr.	116.5	95.2

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
69.69	57.96	15.74	35.17	34.54	41.97	19.69	18.41	26.03	32.58	33.29	28.96	26.55	28.67	31.20	25.48	*28.95*	*33.65*	Revenues per sh	*33.50*
3.68	5.27	4.93	4.26	4.46	4.81	5.04	5.29	2.95	5.41	4.88	4.01	5.59	5.93	6.25	5.67	*6.65*	*7.85*	"Cash Flow" per sh	*8.75*
2.37	3.42	2.33	1.84	1.74	2.11	2.21	2.68	.18	2.32	1.66	1.01	1.97	2.61	2.89	2.83	*2.60*	*3.50*	Earnings per sh A	*4.25*
1.08	1.12	1.16	1.20	1.24	1.28	1.32	1.37	1.40	1.42	1.44	1.46	1.48	1.52	1.56	1.62	1.68	*1.84*	Div'd Decl'd per sh B ■	*2.20*
5.79	14.07	8.65	2.80	2.80	4.18	9.24	6.92	8.51	8.90	12.04	10.03	7.90	7.97	8.92	8.90	*9.06*	*6.05*	Cap'l Spending per sh	*6.50*
11.95	18.95	19.66	21.72	22.43	22.29	23.68	25.66	27.19	27.84	28.02	27.53	27.88	29.39	30.80	28.63	*30.10*	*32.00*	Book Value per sh C	*38.75*
23.30	26.89	26.93	32.30	32.48	33.16	33.37	37.80	38.64	38.97	39.27	43.92	44.21	44.50	44.67	51.19	*53.50*	*54.25*	Common Shs Outst'g D	*61.00*
10.9	11.4	12.5	15.9	17.1	17.3	15.8	15.0	NMF	9.9	18.1	31.1	17.1	18.2	19.0	16.1	*22.5*		Avg Ann'l P/E Ratio	*15.0*
.71	.58	.68	.91	.90	.92	.85	.80	NMF	.66	1.15	1.95	1.09	1.02	1.00	.82	*1.20*		Relative P/E Ratio	*.95*
4.2%	2.9%	4.0%	4.1%	4.2%	3.5%	3.8%	3.4%	4.2%	6.2%	4.8%	4.6%	4.4%	3.2%	2.8%	3.5%	*2.9%*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 9/30/16
Total Debt $3292.5 mill. **Due in 5 Yrs** $963.5 mill.
LT Debt $3211.8 mill. **LT Interest** $125.4 mill.
(LT interest earned: 2.8x)
Leases, Uncapitalized Annual rentals $2.9 mill.

Pension Assets-12/15 $288.6 mill.
Oblig. $356.6 mill.

Pfd Stock None

Common Stock 53,147,805 shs.
as of 10/31/16

MARKET CAP: $3.3 billion (Mid Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
656.9	695.9	1005.8	1269.6	1307.3	1272.2	1173.9	1275.9	1393.6	1304.6	*1550*	*1825*	Revenues ($mill)	*2050*
74.0	100.1	6.8	89.7	64.6	40.4	86.9	115.8	128.8	128.3	*130*	*190*	Net Profit ($mill)	*255*
31.3%	31.3%	33.1%	30.7%	26.4%	31.1%	35.5%	34.7%	33.7%	35.8%	*34.0%*	*30.0%*	Income Tax Rate	*30.0%*
9.7%	14.8%	173.2%	20.1%	28.0%	65.0%	5.4%	2.4%	2.4%	2.7%	*4.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
44.3%	36.8%	32.3%	48.4%	51.9%	51.4%	43.2%	51.6%	47.9%	56.0%	*57.5%*	*59.5%*	Long-Term Debt Ratio	*48.5%*
55.7%	63.2%	67.7%	51.6%	48.1%	48.6%	56.8%	48.4%	52.1%	44.0%	*42.5%*	*40.5%*	Common Equity Ratio	*51.5%*
1418.4	1534.2	1551.8	2100.7	2286.3	2489.7	2171.4	2704.7	2643.6	3332.7	*3790*	*4260*	Total Capital ($mill)	*4600*
1646.4	1823.5	2022.2	2160.7	2495.4	2789.6	2742.7	2990.3	3239.4	3259.1	*4550*	*4640*	Net Plant ($mill)	*4975*
6.8%	7.9%	1.6%	5.9%	4.4%	3.3%	5.5%	5.5%	6.1%	4.9%	*4.5%*	*5.5%*	Return on Total Cap'l	*6.5%*
9.4%	10.3%	.7%	8.3%	5.9%	3.3%	7.1%	8.9%	9.4%	8.8%	*8.5%*	*11.0%*	Return on Shr. Equity	*11.0%*
9.4%	10.3%	.7%	8.3%	5.9%	3.3%	7.1%	8.9%	9.4%	8.8%	*8.5%*	*11.0%*	Return on Com Equity E	*11.0%*
3.8%	5.1%	NMF	3.2%	.7%	NMF	1.8%	3.7%	4.3%	3.8%	*3.0%*	*5.0%*	Retained to Com Eq	*5.0%*
59%	50%	NMF	62%	87%	NMF	75%	58%	54%	57%	*65%*	*52%*	All Div'ds to Net Prof	*53%*

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	+1.0	+2.9	+4.5
Avg. Indust. Use (MWH)	9740	13055	15552
Avg. Indust. Revs. per KWH (¢)	8.19	7.97	8.02
Capacity at Yearend (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	988	992	1028
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.8	+.9	+.9
Fixed Charge Cov. (%)	224	357	324

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	-2.5%	-1.5%	*3.0%*
"Cash Flow"	3.0%	6.0%	*6.5%*
Earnings	4.0%	15.0%	*7.5%*
Dividends	2.5%	2.0%	*6.0%*
Book Value	3.0%	1.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	380.7	279.8	259.9	355.5	1275.9
2014	460.2	283.2	272.1	378.1	1393.6
2015	442.0	272.2	272.1	318.3	1304.6
2016	450.0	325.4	333.8	*440.8*	*1550*
2017	*650*	*350*	*350*	*475*	*1825*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.97	.69	.52	.43	2.61
2014	1.08	.44	.60	.76	2.89
2015	1.07	.55	.58	.63	2.83
2016	.94	.31	.41	*.94*	*2.60*
2017	*1.30*	*.60*	*.65*	*.95*	*3.50*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.38	.38	.38	.38	1.52
2014	.39	.39	.39	.39	1.56
2015	.405	.405	.405	.405	1.62
2016	.42	.42	.42	.42	1.68
2017					

BUSINESS: Black Hills Corporation is a holding company for utilities that serve 207,000 electric customers in CO, SD, WY and MT, and 1 million gas customers in NE, IA, KS, CO, WY, and AR. Mines coal & has a gas & oil E&P business. Acq'd Mallon Resources 3/03; Cheyenne Light 1/05; utility ops. from Aquila 7/08; SourceGas 2/16. Discont. telecom in '05; oil marketing in '06; gas marketing in '11. Electric revenue breakdown: res'l, 31%; comm'l, 38%; ind'l, 16%; other, 15%. Generating sources: coal, 33%; other, 4%; purch., 63%. Fuel costs: 35% of revs. '15 deprec. rate: 3.3%. Has 3,100 employees. Chairman & CEO: David R. Emery. Pres. & COO: Linn Evans. Inc.: SD. Address: P.O. Box 1400, 625 Ninth St., Rapid City, SD 57701. Tel.: 605-721-1700. Internet: www.blackhillscorp.com.

Black Hills' earnings will almost certainly advance significantly in 2017. A year ago, the company acquired SourceGas, which provides gas service to more than 400,000 customers in four states. Black Hills incurred significant integration costs in connection with the SourceGas addition. These reduced earnings by $0.46 a share in the first nine months of 2016, and there were possibly additional expenses in the fourth quarter. What's more, the acquisition was completed in mid-February, so Black Hills did not have SourceGas' income for the first month and a half of 2016 — the seasonally strongest time of year for a gas utility. Our 2017 earnings estimate is within the company's targeted range of $3.45-$3.65 a share.

Black Hills is trying to reduce its exposure to the oil and gas exploration and production business. The company has sold some noncore assets. Even so, this operation will probably post a modest operating loss in 2017. Black Hills plans to retain some gas reserves it believes would be suitable for inclusion in the rate base, in case the company revives a proposal to include cost-of-service gas in the rate base.

The utility was disappointed with a rate order in Colorado. Black Hills filed for a rate hike of $8.5 million, based on a return of 9.83% on a common-equity ratio of 50.9%. The application was made to place a $65 million, 40-megawatt gas-fired unit in the rate base. However, the regulators granted the utility just $636,267, based on a 9.37% ROE. The equity ratio is 52.4%—except for the new plant, which is in rates based on an equity ratio of just 33%. Black Hills has asked the commission for reconsideration and a rehearing.

We think the board of directors will raise the dividend at its upcoming meeting. Black Hills hasn't hinted about its dividend policy, but we think the increase will be significantly greater than the $0.06-a-share annual raise declared in each of the past two years, given the large rise in the company's earning power following the SourceGas deal.

The stock's dividend yield is below the industry average, even when reflecting the increase we estimate. The equity doesn't stand out for 3- to 5-year total return potential, either.

Paul E. Debbas, CFA *January 27, 2017*

(A) Dil. EPS. Excl. nonrec. gains (losses): '05, (99¢); '08, ($1.55); '09, (28¢); '10, 10¢; '12, 4¢; '15, ($3.54); '16, (62¢); gains (losses) on disc. ops.: '05, (7¢); '06, 21¢; '07, (4¢); '08, $4.12; '09, 7¢; '11, 23¢; '12, (16¢). '14 EPS don't add due to rounding. Next egs. due early Feb. (B) Div'ds paid early Mar., Jun., Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '15: $10.52/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in SD in '15: none specified; in CO in '17: 9.37%; earned on avg. com. eq., '15: 9.0%. Reg. Climate: Avg.

Company's Financial Strength	A
Stock's Price Stability	80
Price Growth Persistence	70
Earnings Predictability	50

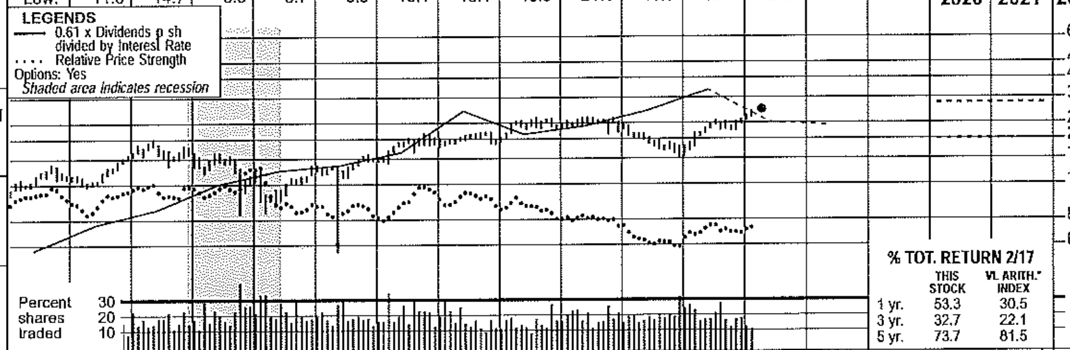
CENTERPOINT EN'RGY NYSE-CNP

RECENT PRICE 28.00 | P/E RATIO 23.1 (Trailing: 28.3; Median: 15.0) | RELATIVE P/E RATIO 1.18 | DIV'D YLD 3.9% | VALUE LINE

TIMELINESS 3 Lowered 3/17/17
SAFETY 3 Lowered 12/18/15
TECHNICAL 3 Lowered 12/30/16
BETA .85 (1.00 = Market)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
High:	16.9	20.2	17.3	14.9	17.0	21.5	21.8	25.7	25.8	23.7	25.0	28.1
Low:	11.6	14.7	8.5	8.7	5.5	15.1	18.1	19.3	21.1	16.0	16.4	24.5

LEGENDS
— 0.61 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2020 | 2021 | 2022

2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+5%)	6%
Low	20	(-30%)	-3%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	7	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	0	0	1	0	0

Institutional Decisions

	2Q2016	3Q2016	4Q2016
to Buy	250	246	265
to Sell	186	183	212
Hld's(000)	333863	318487	323268

Percent shares traded 30 20 10

% TOT. RETURN 2/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	53.3	30.5
3 yr.	32.7	22.1
5 yr.	73.7	81.5

2001A	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
35.18	26.40	31.87	27.63	31.33	29.71	29.62	32.71	21.14	20.69	19.83	17.43	18.90	21.51	17.18	17.48	**18.00**	**18.55**	Revenues per sh	**20.25**
3.69	3.34	3.98	2.56	2.72	3.47	3.39	3.42	2.94	3.14	3.43	3.89	3.54	3.85	3.40	3.68	**4.05**	**4.25**	"Cash Flow" per sh	**4.75**
1.54	1.29	1.37	.61	.67	1.33	1.17	1.30	1.01	1.07	1.27	1.35	1.24	1.42	1.08	1.00	**1.30**	**1.40**	Earnings per sh B	**1.65**
1.50	1.07	.40	.40	.40	.60	.68	.73	.76	.78	.79	.81	.83	.95	.99	1.03	**1.07**	**1.11**	Div'd Decl'd per sh C ■	**1.23**
6.78	2.85	2.11	1.72	2.23	3.21	3.45	2.95	2.96	3.55	3.06	2.84	3.00	3.20	3.68	3.28	**3.50**	**3.30**	Cap'l Spending per sh	**3.00**
22.24	4.74	5.75	3.59	4.18	4.96	5.61	5.89	6.74	7.53	9.91	10.06	10.09	10.60	8.05	8.03	**8.25**	**8.55**	Book Value per sh D	**9.75**
302.94	300.10	306.30	308.05	310.33	313.65	322.72	346.09	391.75	424.70	426.03	427.44	429.00	429.00	430.00	430.68	**431.00**	**431.00**	Common Shs Outst'g E	**435.00**
--	5.6	6.0	17.8	19.1	10.3	15.0	11.3	11.8	13.8	14.6	14.8	18.7	17.0	18.1	21.9	*Bold figures are*	*Value Line estimates*	Avg Ann'l P/E Ratio	**16.0**
--	.31	.34	.94	1.02	.56	.80	.68	.79	.88	.92	.94	1.05	.89	.91	1.15			Relative P/E Ratio	**1.00**
--	14.8%	4.8%	3.7%	3.1%	4.4%	3.9%	5.0%	6.4%	5.3%	4.3%	4.0%	3.6%	3.9%	5.1%	4.7%			Avg Ann'l Div'd Yield	**4.7%**

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
9623.0	11322	8281.0	8785.0	8450.0	7452.0	8106.0	9226.0	7386.0	7528.0	**7750**	**8000**	Revenues ($mill)	**8800**
399.0	447.0	372.0	442.0	546.0	581.0	536.0	611.0	465.0	432.0	**560**	**605**	Net Profit ($mill)	**720**
32.8%	38.3%	32.1%	37.3%	33.6%	33.4%	31.4%	31.0%	35.1%	37.0%	**36.0%**	**36.0%**	Income Tax Rate	**36.0%**
5.5%	2.7%	1.3%	2.7%	1.6%	2.6%	3.5%	4.1%	4.7%	3.5%	**4.0%**	**4.0%**	AFUDC % to Net Profit	**3.0%**
82.2%	83.3%	77.6%	73.8%	67.2%	66.0%	64.4%	63.8%	69.5%	68.5%	**67.5%**	**67.0%**	Long-Term Debt Ratio	**65.5%**
17.8%	16.7%	22.4%	26.2%	32.8%	34.0%	35.6%	36.2%	30.5%	31.5%	**32.5%**	**33.0%**	Common Equity Ratio	**34.5%**
10174	12218	11758	12199	12863	12658	12146	12557	11362	10992	**11000**	**11225**	Total Capital ($mill)	**12400**
9740.0	10296	10788	11732	12402	13597	9593.0	10502	11537	12307	**12875**	**13325**	Net Plant ($mill)	**14100**
6.9%	6.0%	5.8%	6.1%	6.4%	6.8%	6.3%	6.7%	6.1%	5.8%	**7.0%**	**7.0%**	Return on Total Cap'l	**7.5%**
22.0%	21.9%	14.1%	13.8%	12.9%	13.5%	12.4%	13.4%	13.4%	12.5%	**15.5%**	**16.5%**	Return on Shr. Equity	**17.0%**
22.0%	21.9%	14.1%	13.8%	12.9%	13.5%	12.4%	13.4%	13.4%	12.5%	**15.5%**	**16.5%**	Return on Com Equity F	**17.0%**
10.0%	9.9%	3.6%	3.8%	5.0%	5.5%	4.2%	4.5%	1.1%	NMF	**3.0%**	**3.5%**	Retained to Com Eq	**4.5%**
55%	55%	74%	72%	62%	60%	66%	67%	92%	103%	**82%**	**79%**	All Div'ds to Net Prof	**74%**

CAPITAL STRUCTURE as of 12/31/16
Total Debt $8478 mill. Due in 5 Yrs $5029 mill.
LT Debt $7532 mill. LT Interest $373 mill.
Incl. $1931 mill. securitized transition & system restoration bonds.
(LT interest earned: 2.6x)
Leases, Uncapitalized Annual rentals $5 mill.
Pension Assets-12/16 $1656 mill. Oblig $2197 mill.

Pfd Stock None
Common Stock 430,688,867 shs. as of 2/10/17
MARKET CAP: $12 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+2.3	+2.9	+3.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+2.4	+2.1	+2.3
Fixed Charge Cov. (%)	194	200	219

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	-4.5%	-2.0%	1.5%
"Cash Flow"	2.5%	3.0%	4.5%
Earnings	3.0%	1.0%	6.0%
Dividends	8.0%	5.0%	3.5%
Book Value	7.5%	2.0%	1.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2014	3163	1884	1807	2372	9226.0
2015	2433	1532	1630	1791	7386.0
2016	1984	1574	1889	2081	7528.0
2017	*2200*	*1650*	*1750*	*2150*	*7750*
2018	*2300*	*1700*	*1800*	*2200*	*8000*

Cal-endar	EARNINGS PER SHARE B Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2014	.43	.25	.33	.41	1.42
2015	.30	.18	.34	.26	1.08
2016	.36	d.01	.41	.23	1.00
2017	*.36*	*.22*	*.40*	*.32*	*1.30*
2018	*.39*	*.23*	*.43*	*.35*	*1.40*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.207	.207	.207	.207	.83
2014	.237	.237	.238	.238	.95
2015	.247	.247	.248	.248	.99
2016	.258	.258	.258	.258	1.03
2017	.268				

BUSINESS: CenterPoint Energy, Inc. is a holding company for Houston Electric, which serves 2.4 million customers in Houston and environs, and gas utilities with 3.4 million customers in Texas, Minnesota, Arkansas, Louisiana, and Oklahoma. Owns 55.4% of Enable Midstream Partners. Discontinued Texas Genco Holdings in '04. Electric revenue breakdown: residential, 52%; commercial, 31%; industrial, 15%; other, 2%. Does not own generating assets. Gas costs: 39% of revenues. '16 depreciation rate: 6.5%. Has 7,700 employees. Chairman: Milton Carroll. President & CEO: Scott M. Prochazka. Incorporated: Texas. Address: 1111 Louisiana, P.O. Box 4567, Houston, Texas 77210-4567. Telephone: 713-207-1111. Internet: www.centerpointenergy.com.

CenterPoint Energy still hasn't decided what to do with its 55.4% stake in Enable Midstream Partners. CenterPoint is concerned about the volatility associated with its interest in Enable, a natural gas master limited partnership. The company prefers the relative stability of its regulated electric and gas utilities and its retail energy-services operations. A straightforward sale of this stake would result in a large tax liability. Another option is a spinoff. Or CenterPoint can work with Enable management to reduce the MLP's exposure to commodity prices. Management now expects to announce a decision by the time it reports second-quarter results, probably in early August.

Earnings are likely to advance materially this year. The comparison is easy, as profits in 2016 were hurt by mark-to-market accounting charges amounting to $0.16 a share. (We *include* these in our earnings presentation because they are an ongoing part of CenterPoint's results.) Still, the company is benefiting from rate relief, customer growth (2% for electricity and 1% for gas), and its expanding retail energy-services subsidiary. The latter operation made significant acquisitions in 2016 and early 2017. In addition, we look for a greater contribution from CenterPoint's interest in Enable, as our figures are based on the company's current configuration. Our earnings estimate is within management's targeted range of $1.25-$1.33 a share. We forecast more-modest, but still solid, profit growth in 2018, based on the same factors that should help results this year.

The board of directors raised the dividend in early 2017. The increase was a cent a share (3.9%) quarterly. CenterPoint can maintain a high payout ratio thanks to the distributions it receives from its stake in Enable.

The price of CenterPoint stock has risen 14% so far this year. We think the improving prospects of Enable have helped; note that OGE Energy, another owner of Enable, has climbed 10% in 2017. The dividend yield is a cut above the utility mean. With the recent quotation near the upper end of our 2020-2022 Target Price Range, total return potential is minuscule.

Paul E. Debbas, CFA *March 17, 2017*

(A) Pro forma data. (B) Diluted EPS. Excl. extraordinary gains (losses): '04, ($2.72); '05, 9¢; '11, $1.89; '12, (38¢) net; '13, (52¢); '15, ($2.69); losses on disc. ops.: '04, 37¢; '05, 1¢. '16 EPS don't sum due to rounding. Next earnings report due early May. (C) Div'ds historically paid in early Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. (D) Incl. intang. In '16: $8.22/sh. (E) In mill. (F) Rate base: Net original cost. Rate allowed on com. eq. (elec.) in '11: 10%; (gas): 9.45%-11.25%; earned on avg. com. eq., '16: 12.4%%. Regulat. Climate: Avg.

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	50
Earnings Predictability	85

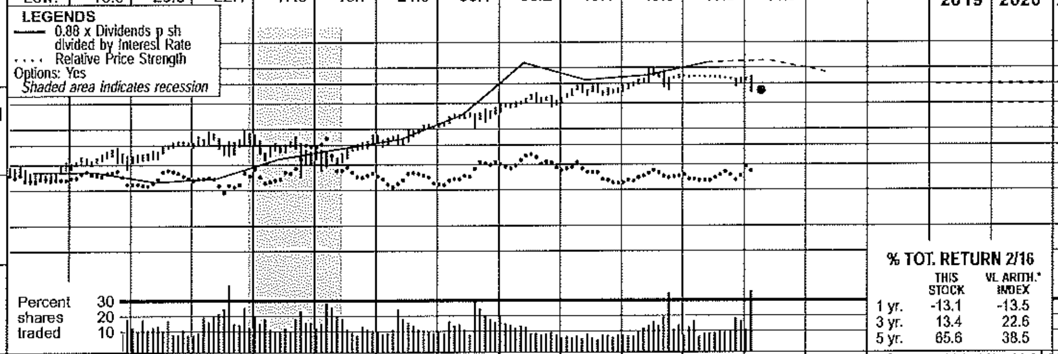
CLECO CORPORATION NYSE-CNL

RECENT PRICE	46.42	P/E RATIO	20.5 (Trailing: 21.1; Median: 15.0)	RELATIVE P/E RATIO	1.16	DIV'D YLD	3.6%	VALUE LINE

TIMELINESS 3 New 3/4/16
SAFETY 1 Raised 6/22/12
TECHNICAL 1 Raised 3/11/16
BETA .70 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	24.4	26.2	29.8	28.4	28.1	31.8	38.3	45.3	50.4	59.2	55.2	54.5
Low:	18.9	20.5	22.1	17.3	18.7	24.3	30.1	36.2	40.4	45.5	48.5	44.8

Target Price Range 2019 | 2020 | 2021



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+10%)	6%
Low	40	(-15%)	1%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	1	0	0	1	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2015	3Q2015	4Q2015
to Buy	97	97	94
to Sell	106	96	101
Hld's(000)	45428	46967	45747

% TOT. RETURN 2/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-13.1	-13.5
3 yr.	13.4	22.6
5 yr.	65.6	38.5

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
18.23	23.55	15.33	18.54	15.03	18.41	17.38	17.19	17.99	14.17	18.98	18.53	16.46	18.14	21.01	20.00	21.05	22.15	Revenues per sh	25.25
2.77	2.94	3.05	2.98	2.56	2.76	2.63	2.69	3.71	3.78	5.12	5.28	5.40	5.32	5.15	4.85	5.10	5.35	"Cash Flow" per sh	6.50
1.46	1.51	1.52	1.26	1.32	1.42	1.36	1.32	1.70	1.76	2.29	2.59	2.70	2.65	2.55	2.20	2.25	2.35	Earnings per sh A	2.75
.85	.87	.90	.90	.90	.90	.90	.90	.90	.90	.98	1.12	1.30	1.43	1.56	1.60	1.63	1.68	Div'd Decl'd per sh B ■	1.80
2.52	1.10	1.91	1.58	1.61	3.19	4.11	8.51	5.59	4.15	4.68	3.25	4.06	3.12	3.44	2.60	4.30	3.05	Cap'l Spending per sh	3.25
10.04	10.69	11.77	10.09	10.83	13.69	15.22	16.85	17.65	18.50	21.76	23.55	24.84	26.24	26.93	27.70	28.35	29.05	Book Value per sh C	31.50
44.99	44.96	47.04	47.18	49.62	49.99	57.57	59.94	60.04	60.26	60.53	60.29	60.36	60.45	60.42	60.50	60.50	60.50	Common Shs Outst'g D	60.50
13.2	14.6	12.2	12.4	13.8	15.0	17.3	19.6	14.1	13.2	12.3	13.3	15.0	17.3	20.5	24.4	Bold figures are		Avg Ann'l P/E Ratio	16.0
.86	.75	.67	.71	.73	.80	.93	1.04	.85	.88	.78	.83	.95	.97	1.08	1.24	Value Line		Relative P/E Ratio	1.00
4.4%	3.9%	4.8%	5.8%	5.0%	4.2%	3.8%	3.5%	3.8%	3.9%	3.5%	3.3%	3.2%	3.1%	3.0%	3.0%	estimates		Avg Ann'l Div'd Yield	4.0%

CAPITAL STRUCTURE as of 9/30/15
Total Debt $1226.6 mill. Due in 5 Yrs $466.2 mill.
LT Debt $1207.2 mill. LT Interest $69.4 mill.
Incl. $4.4 million capitalized leases.
(LT interest earned: 3.5x)

Leases, Uncapitalized Annual rentals $10.3 mill.
Pension Assets-12/14 $412.8 mill. Oblig. $498.4 mill.

Pfd Stock None

Common Stock 60,482,051 shs.
as of 10/21/15
MARKET CAP: $2.8 billion (Mid Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
1000.7	1030.6	1080.2	853.8	1148.7	1117.3	993.7	1096.7	1269.5	1209.4	1275	1340	Revenues ($mill)	1525
74.7	79.6	102.1	106.3	139.5	157.8	163.6	160.7	154.7	133.7	140	145	Net Profit ($mill)	165
36.0%	24.3%	15.3%	8.3%	44.1%	30.6%	28.5%	33.1%	30.3%	36.8%	38.5%	38.5%	Income Tax Rate	38.5%
14.2%	57.9%	82.8%	93.5%	12.2%	4.3%	5.5%	3.4%	4.5%	3.0%	3.0%	3.0%	AFUDC % to Net Profit	2.0%
40.9%	43.2%	51.1%	54.2%	51.5%	48.5%	45.6%	45.3%	45.3%	46.0%	45.5%	40.0%	Long-Term Debt Ratio	42.5%
57.8%	56.7%	48.9%	45.8%	48.5%	51.5%	54.4%	54.7%	54.7%	54.0%	54.5%	60.0%	Common Equity Ratio	57.5%
1515.6	1780.5	2167.7	2436.4	2717.9	2756.9	2756.5	2901.7	2976.9	3100	3140	2930	Total Capital ($mill)	3325
1304.9	1725.9	2045.3	2247.0	2784.2	2893.9	3009.5	3083.1	3165.5	3191.6	3280	3285	Net Plant ($mill)	3250
6.3%	5.6%	6.1%	5.9%	6.6%	7.0%	7.3%	6.8%	6.4%	5.5%	5.5%	6.0%	Return on Total Cap'l	6.0%
8.3%	7.9%	9.6%	9.5%	10.6%	11.1%	10.9%	10.1%	9.5%	8.0%	8.0%	8.0%	Return on Shr. Equity	8.5%
8.3%	7.8%	9.6%	9.5%	10.6%	11.1%	10.9%	10.1%	9.5%	8.0%	8.0%	8.0%	Return on Com Equity E	8.5%
3.0%	2.6%	4.5%	4.7%	6.1%	6.3%	5.7%	4.7%	3.7%	2.0%	2.5%	2.5%	Retained to Com Eq	3.0%
65%	68%	53%	51%	42%	43%	48%	54%	61%	72%	71%	71%	All Div'ds to Net Prof	65%

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-3.4	+1.4	-.3
Avg. Indust. Use (MWH)	3814	3870	3756
Avg. Indust. Revs. per KWH (¢)	6.83	7.50	7.49
Capacity at Peak (Mw)	3315	3315	3360
Peak Load, Summer (Mw)	2282	2278	2612
Annual Load Factor (%)	55.1	57.0	57.1
% Change Customers (avg.)	+.6	+.6	+.5
Fixed Charge Cov. (%)	326	360	380

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '19-'21
Revenues	1.5%	2.5%	4.5%
"Cash Flow"	6.5%	9.5%	3.0%
Earnings	7.0%	10.5%	.5%
Dividends	5.0%	9.5%	3.5%
Book Value	9.0%	8.0%	3.0%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	240.9	263.9	328.8	263.1	1096.7
2014	284.4	309.1	371.4	304.6	1269.5
2015	295.4	289.1	345.5	279.4	1209.4
2016	305	310	355	305	1275
2017	320	325	375	320	1340

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.45	.69	1.09	.41	2.65
2014	.43	.60	1.17	.35	2.55
2015	.44	.50	.90	.36	2.20
2016	.35	.55	1.00	.35	2.25
2017	.40	.57	1.03	.35	2.35

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.3125	.3125	.3375	.3375	1.30
2013	.3375	.3625	.3625	.3625	1.43
2014	.3625	.40	.40	.40	1.56
2015	.40	.40	.40	.40	1.60
2016	.40				

BUSINESS: Cleco Corporation is a holding company for Cleco Power LLC, which supplies electricity to about 286,000 customers in central Louisiana. Electric revenue breakdown: residential, 46%; commercial, 30%; industrial, 14%; other, 10%. Largest industrial customers are paper mills and other wood-product industries. Generating sources: gas & oil, 26%; petroleum coke, 26%; coal & lignite, 23%; purchased, 25%. Fuel costs: 44% of revenues. '14 reported depreciation rate (utility): 2.7%. Has 1,200 employees. Chairman: J. Patrick Garrett. President & CEO: Bruce A. Williamson. Incorporated: Louisiana. Address: 2030 Donahue Ferry Road, P.O. Box 5000, Pineville, Louisiana 71361-5000. Telephone: 318-484-7400. Internet: www.cleco.com.

The Louisiana Public Service Commission (LPSC) rejected the proposed acquisition of Cleco. An investor group led by Macquarie Infrastructure Partners and British Columbia Energy agreed to pay $55.37 a share in cash for each share of Cleco. However, some intervenors opposed the transaction, and the LPSC did not approve it. Whether the objection was more related to foreign ownership or the specific deal is uncertain.

The companies have not given up. They asked the LPSC for an immediate rehearing, and requested placement on the LPSC's Supplemental Agenda for its meeting on March 16th (in between the time this report went to press and the time it came out in print). If the companies' request proves unsuccessful, they can seek relief in the courts. However . . .

The stock is trading as though the deal is already dead. Due to the LPSC's rejection of the proposed combination, the share price of Cleco is down 11% year to date, in what has been a good year for most utility equities. Because the stock is no longer trading on takeover considerations, we restored its Timeliness rank.

We estimate that earnings will advance this year and next. In 2015, costs associated with the proposed acquisition (*included* in our earnings presentation) reduced profits by $0.08 a share. We figure that these expenses will be lower this year, and nonexistent in 2017. In addition, the utility benefits from a formula rate-making plan that provides some additional revenues every year without having to file a general rate case. Note that Cleco has not provided earnings guidance for 2016, nor has it stated any expectation for the dividend.

If the deal is terminated, we think there is a chance of a dividend increase in the second quarter. The board of directors has not raised the disbursement while the attempted takeover was pending. We look for an increase of a cent a share (2.5%) in the quarterly payout at the first dividend meeting following the termination of the proposed acquisition.

The dividend yield of Cleco stock is about equal to the mean for electric utilities. Total return potential over the 3- to 5-year period is unimpressive.

Paul E. Debbas, CFA *March 18, 2016*

(A) Diluted earnings. Excl. nonrec. gains (losses): '00, 5¢; '02, (5¢), '03, ($2.05); '05, $2.11; '07, $1.22; '10, $1.91; '11, 63¢; losses from discontinued operations: '00, 14¢; '01, 4¢. '13 EPS don't add due to rounding. Next earnings report due early May. (B) Div'ds historically paid in mid-Feb., May, Aug. and Nov. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '14: $10.89/sh. (D) In mill. (E) Rate base: Net original cost. Rate allowed on com. eq. in '14: 11.24%; earned on avg. com. eq., '14: 9.6%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	80

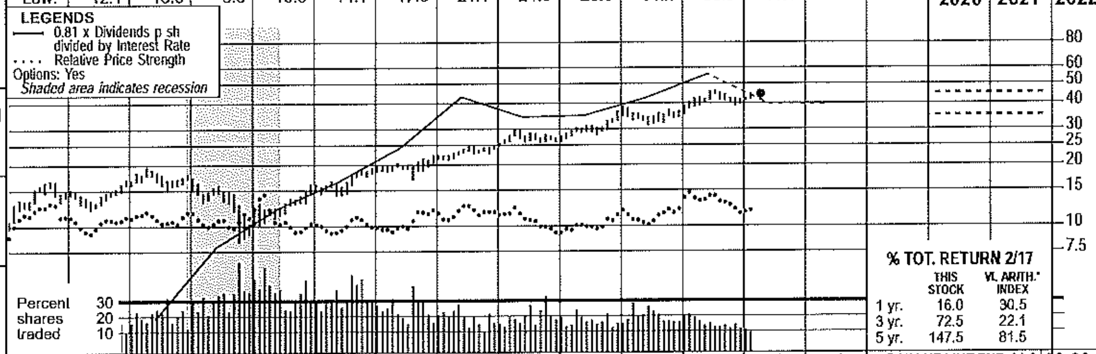
CMS ENERGY CORP. NYSE-CMS

RECENT PRICE 44.44 | P/E RATIO 22.4 (Trailing: 22.3 Median: 16.0) | RELATIVE P/E RATIO 1.15 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS 3 Raised 12/30/16
SAFETY 2 Raised 3/21/14
TECHNICAL 3 Lowered 9/30/16
BETA .65 (1.00 = Market)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
High:	17.0	19.5	17.5	16.1	19.3	22.4	25.0	30.0	36.9	38.7	46.3	44.8
Low:	12.1	15.0	8.3	10.0	14.1	17.0	21.1	24.6	26.0	31.2	35.0	41.1

Target Price Range 2020 | 2021 | 2022



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(Nil)	4%
Low	35	(-20%)	-1%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	1	0	0
Options	10	0	1	0	1	0	0	0	11
to Sell	4	0	0	3	0	0	0	0	0

Institutional Decisions

	2Q2016	3Q2016	4Q2016
to Buy	236	203	232
to Sell	201	225	218
Hld's(000)	251054	246256	246703

% TOT. RETURN 2/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.0	30.5
3 yr.	72.5	22.1
5 yr.	147.5	81.5

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
72.16	60.28	34.21	28.06	28.52	30.57	28.95	30.13	27.23	25.77	25.59	23.90	24.68	26.09	23.29	22.92	*23.15*	*23.85*	Revenues per sh	*26.00*
5.24	d.09	2.39	2.87	3.43	3.22	3.08	3.88	3.47	3.70	3.65	3.82	4.06	4.22	4.59	4.88	*5.30*	*5.65*	"Cash Flow" per sh	*7.00*
1.27	d2.99	d.29	.74	1.10	.64	.64	1.23	.93	1.33	1.45	1.53	1.66	1.74	1.89	1.98	*2.15*	*2.30*	Earnings per sh A	*2.75*
1.46	1.09	--	--	--	--	.20	.36	.50	.66	.84	.96	1.02	1.08	1.16	1.24	*1.33*	*1.42*	Div'd Decl'd per sh B ■	*1.70*
9.49	5.18	3.32	2.69	2.69	3.01	5.61	3.50	3.59	3.29	3.47	4.65	4.98	5.73	5.64	5.99	*6.55*	*6.65*	Cap'l Spending per sh	*6.25*
14.21	7.86	9.84	10.63	10.53	10.03	9.46	10.88	11.42	11.19	11.92	12.09	12.98	13.34	14.21	15.23	*16.30*	*17.40*	Book Value per sh C	*21.00*
132.99	144.10	161.13	195.00	220.50	222.78	225.15	226.41	227.89	249.60	254.10	264.10	266.10	275.20	277.16	279.21	*281.00*	*283.00*	Common Shs Outst'g D	*289.00*
20.8	--	--	12.4	12.6	22.2	26.8	10.9	13.6	12.5	13.6	15.1	16.3	17.3	18.3	20.9	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
1.07	--	--	.66	.67	1.20	1.42	.66	.91	.80	.85	.96	.92	.91	.92	1.10	*Value Line*		Relative P/E Ratio	*.90*
5.5%	7.5%	--	--	--	--	1.2%	2.7%	4.0%	4.0%	4.3%	4.2%	3.8%	3.6%	3.4%	3.0%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*

CAPITAL STRUCTURE as of 12/31/16
Total Debt $10034 mill. Due in 5 Yrs $4608 mill.
LT Debt $8750 mill. LT Interest $389 mill.
Incl. $110 mill. capitalized leases.
(LT interest earned: 3.0x)
Leases, Uncapitalized Annual rentals $20 mill.
Pension Assets-12/16 $2101 mill.
Oblig $2562 mill.
Pfd Stock $37 mill. Pfd Div'd $2 mill.
Incl. 373,148 shs. $4.50 $100 par, cum., callable at $110.00.
Common Stock 279,205,000 shs.

MARKET CAP: $12 billion (Large Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
6519.0	6821.0	6205.0	6432.0	6503.0	6312.0	6566.0	7179.0	6456.0	6399.0	*6500*	*6750*	Revenues ($mill)	*7500*
168.0	300.0	231.0	356.0	384.0	413.0	454.0	479.0	525.0	553.0	*610*	*655*	Net Profit ($mill)	*805*
37.6%	31.6%	34.6%	38.1%	36.8%	39.4%	39.9%	34.3%	34.0%	33.1%	*34.0%*	*34.0%*	Income Tax Rate	*34.0%*
3.6%	1.3%	13.0%	2.2%	2.6%	2.9%	2.0%	2.3%	2.7%	3.1%	*3.0%*	*3.0%*	AFUDC % to Net Profit	*2.0%*
70.5%	69.4%	67.9%	70.1%	66.9%	67.9%	67.5%	68.7%	68.3%	67.1%	*66.5%*	*65.5%*	Long-Term Debt Ratio	*64.5%*
25.9%	27.4%	29.0%	29.5%	32.6%	31.6%	32.2%	31.0%	31.4%	32.6%	*33.5%*	*34.0%*	Common Equity Ratio	*35.5%*
8212.0	8993.0	8977.0	9473.0	9279.0	10101	10730	11846	12534	13040	*13725*	*14450*	Total Capital ($mill)	*17100*
8728.0	9190.0	9682.0	10069	10633	11551	12246	13412	14705	15715	*16675*	*17600*	Net Plant ($mill)	*19800*
4.5%	5.4%	4.7%	5.8%	6.3%	5.9%	6.0%	5.7%	5.7%	5.8%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
6.9%	10.9%	8.0%	12.5%	12.5%	12.8%	13.0%	12.9%	13.2%	12.9%	*13.0%*	*13.0%*	Return on Shr. Equity	*13.0%*
7.2%	11.7%	8.5%	12.5%	12.6%	12.9%	13.1%	13.0%	13.3%	13.0%	*13.5%*	*13.5%*	Return on Com Equity E	*13.5%*
5.1%	8.4%	4.1%	6.9%	5.6%	5.0%	5.2%	5.0%	5.2%	4.8%	*5.0%*	*5.0%*	Retained to Com Eq	*5.0%*
35%	31%	54%	46%	55%	61%	60%	62%	61%	63%	*61%*	*61%*	All Div'ds to Net Prof	*61%*

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+1.9	-.8	+1.7
Avg. Indust. Use (MWH)	NMF	5922	NA
Avg. Indust. Revs. per KWH (¢)	8.79	8.07	NA
Capacity at Peak (Mw)	8776	8762	NA
Peak Load, Summer (Mw)	7498	7812	NA
Annual Load Factor (%)	59.7	56.8	NA
% Change Customers (yr-end)	--	+.6	+.1
Fixed Charge Cov. (%)	278	288	292

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	-2.0%	-1.5%	*1.5%*
"Cash Flow"	3.5%	5.0%	*7.5%*
Earnings	8.5%	8.5%	*6.5%*
Dividends	--	11.5%	*6.5%*
Book Value	3.0%	4.5%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	2523	1468	1430	1758	7179.0
2015	2111	1350	1486	1509	6456.0
2016	1801	1371	1587	1640	6399.0
2017	*1900*	*1400*	*1550*	*1650*	*6500*
2018	*2000*	*1450*	*1600*	*1700*	*6750*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.75	.30	.34	.35	1.74
2015	.73	.25	.53	.38	1.89
2016	.59	.45	.67	.28	1.98
2017	*.70*	*.40*	*.60*	*.45*	*2.15*
2018	*.80*	*.40*	*.65*	*.45*	*2.30*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.255	.255	.255	.255	1.02
2014	.27	.27	.27	.27	1.08
2015	.29	.29	.29	.29	1.16
2016	.31	.31	.31	.31	1.24
2017	.3325				

BUSINESS: CMS Energy Corporation is a holding company for Consumers Energy, which supplies electricity and gas to lower Michigan (excluding Detroit). Has 1.8 million electric, 1.7 million gas customers. Has 1,034 megawatts of nonregulated generating capacity. Sold Palisades nuclear plant in '07. Electric revenue breakdown: residential, 45%; commercial, 31%; industrial, 18%; other, 6%. Generating sources: coal, 27%; gas, 16%; other, 3%; purchased, 54%. Fuel costs: 44% of revenues. '16 reported deprec. rates: 3.9% electric, 2.9% gas, 9.8% other. Has 7,400 employees. Chairman: John G. Russell. President & CEO: Patti Poppe. Incorporated: Michigan. Address: One Energy Plaza, Jackson, Michigan 49201. Tel.: 517-788-0550. Internet: www.cmsenergy.com.

CMS Energy's utility subsidiary received an electric rate increase. The Michigan Public Service Commission (MPSC) granted Consumers Energy a rate hike of $113 million, based on 10.1% return on equity. The utility had sought a boost of $225 million, based on a 10.3% ROE. New tariffs went into effect on March 7th.

The utility self-implemented an interim gas rate increase in late January. The increase was $20 million, effective January 29th. Consumers Energy is seeking a hike of $90 million, based on a 10.6% ROE. The MPSC's final decision is due by the end of July.

Earnings should advance nicely this year and next. Consumers Energy will benefit from the aforementioned rate matters. In addition, the company is benefiting from a cost-management program that should see a reduction of 2%-3% annually in operating and maintenance expenses. Our 2017 estimate is within CMS Energy's typically narrow guidance of $2.14-$2.18 a share. (Management raised this by a cent upon its fourth-quarter earnings release in early February.) For 2018, we forecast a bottom-line increase in line with the company's annual goal of 6%-8%.

The board of directors raised the dividend in the first quarter. The increase was $0.09 a share (7.3%). This is in line with CMS Energy's target for yearly profit growth.

The utility has asked the MPSC to approve the buyout of a purchased-power contract with Entergy, the owner of the Palisades nuclear plant. Current market prices for power are well below the prices specified in the contract. If the $172 million buyout is approved, the contract will terminate in 2018 instead of 2022, and Consumers Energy will issue securitized bonds for the amount of the payment. The company expects to hear from the MPSC in August.

CMS Energy's strengths are reflected in the stock price, in our view. This reflects the company's solid earnings and dividend growth potential. With the equity's recent quotation near the upper end of our 2020-2022 Target Price Range, total return potential is negligible.

Paul E. Debbas, CFA *March 17, 2017*

(A) Diluted EPS. Excl. nonrec. gains (losses): '05, ($1.61); '06, ($1.08); '07, ($1.26); '09, (7¢); '10, 3¢; '11, 12¢; '12, (14¢); gains (losses) on disc. ops.: '05, 7¢; '06, 3¢; '07, (40¢); '09, 8¢; '10, (8¢); '11, 1¢; '12, 3¢. '16 EPS don't sum due to rounding. Next earnings report due late Apr. (B) Div'ds historically paid late Feb., May, Aug., & Nov. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '16: $7.49/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '17: 10.1%; earned on avg. com. eq., '16: 13.5%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	90
Earnings Predictability	80

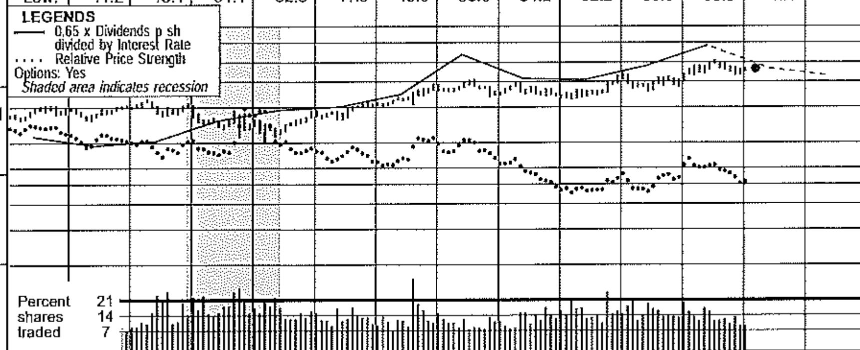
CON. EDISON NYSE-ED

RECENT PRICE 74.30 | P/E RATIO 17.9 (Trailing: 19.0; Median: 15.0) | RELATIVE P/E RATIO 0.92 | DIV'D YLD 3.7% | VALUE LINE

TIMELINESS 2 Raised 1/20/17														
SAFETY 1 New 7/27/90	High:	49.3	52.9	49.3	46.3	51.0	62.7	66.0	64.0	68.9	72.3	81.9	74.8	Target Price Range
TECHNICAL 3 Raised 1/20/17	Low:	41.2	43.1	34.1	32.6	41.5	48.6	53.6	54.2	52.2	56.9	63.5	72.1	2020 / 2021 / 2022

BETA .55 (1.00 = Market)

LEGENDS
— 0.65 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+10%)	6%
Low	65	(-15%)	1%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	1	0	8	8	10	8	8	11	8	7
Options	2	9	0	2	0	0	2	0	0
to Sell	0	0	0	0	0	0	0	0	1

Institutional Decisions

	1Q2016	2Q2016	3Q2016
to Buy	368	375	322
to Sell	275	265	313
Hld's(000)	163563	167516	162537

Percent shares traded 21 / 14 / 7

% TOT. RETURN 1/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	11.2	31.2
3 yr.	54.3	25.8
5 yr.	54.7	84.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
45.41	39.65	43.51	40.24	47.66	47.14	48.23	49.62	46.36	45.69	44.17	41.62	42.27	44.11	42.85	39.35	40.35	41.55	Revenues per sh	45.25
5.70	5.44	5.12	4.54	5.27	5.28	5.77	5.99	5.86	6.24	6.61	7.15	7.45	7.30	7.93	7.80	8.30	8.65	"Cash Flow" per sh	9.75
3.21	3.13	2.83	2.32	2.99	2.95	3.48	3.36	3.14	3.47	3.57	3.86	3.93	3.62	4.05	3.95	4.15	4.30	Earnings per sh A	4.75
2.20	2.22	2.24	2.26	2.28	2.30	2.32	2.34	2.36	2.38	2.40	2.42	2.46	2.52	2.60	2.68	2.76	2.84	Div'd Decl'd per sh B ■	3.08
5.20	5.68	5.72	5.60	6.59	7.17	7.09	8.50	7.80	6.96	6.72	7.06	8.67	8.26	10.42	14.45	12.25	12.25	Cap'l Spending per sh	11.25
26.71	27.68	28.44	29.09	29.80	31.09	32.58	35.43	36.46	37.93	39.05	40.53	41.81	42.94	44.55	46.80	48.35	49.95	Book Value per sh C	55.00
212.15	213.93	225.84	242.51	245.29	257.46	272.02	273.72	281.12	291.62	292.89	292.87	292.87	292.88	293.00	305.00	306.00	307.00	Common Shs Outst'g D	310.00
12.0	13.3	14.3	18.2	15.1	15.5	13.8	12.3	12.5	13.3	15.1	15.4	14.7	15.9	15.6	18.8	Bold figures are		Avg Ann'l P/E Ratio	15.5
.61	.73	.82	.96	.80	.84	.73	.74	.83	.85	.95	.98	.83	.84	.79	1.00	Value Line		Relative P/E Ratio	.95
5.7%	5.3%	5.5%	5.3%	5.0%	5.0%	4.8%	5.7%	6.0%	5.2%	4.5%	4.1%	4.3%	4.4%	4.1%	3.6%	estimates		Avg Ann'l Div'd Yield	4.2%

CAPITAL STRUCTURE as of 9/30/16
Total Debt $14694 mill. Due in 5 Yrs $2603 mill.
LT Debt $13747 mill. LT Interest $625 mill.
(LT interest earned: 3.8x)

Leases, Uncapitalized Annual rentals $18 mill.

Pension Assets-12/15 $11759 mill. Oblig $14377 mill.

Pfd Stock None

Common Stock 304,727,523 shs. as of 10/28/16
MARKET CAP: $23 billion (Large Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
13120	13583	13032	13325	12938	12188	12381	12919	12554	12000	12350	12750	Revenues ($mill)	14000
936.0	933.0	868.0	992.0	1062.0	1141.0	1157.0	1066.0	1193.0	1190	1285	1330	Net Profit ($mill)	1460
32.6%	36.0%	34.2%	36.0%	36.1%	34.5%	31.8%	34.0%	33.6%	34.0%	34.0%	34.0%	Income Tax Rate	34.0%
1.9%	1.7%	2.6%	2.4%	1.6%	.5%	.5%	.3%	.7%	1.0%	1.0%	1.0%	AFUDC % to Net Profit	1.0%
45.6%	48.3%	48.5%	48.6%	46.5%	45.9%	46.1%	48.0%	47.9%	49.5%	46.5%	48.0%	Long-Term Debt Ratio	45.5%
53.1%	50.6%	50.4%	50.4%	52.5%	54.1%	53.9%	52.0%	52.1%	50.5%	53.5%	52.0%	Common Equity Ratio	54.5%
16687	19160	20330	21952	21794	21933	22735	24207	25058	28150	27525	29550	Total Capital ($mill)	31200
19914	20874	22464	23863	25093	26939	28436	29827	32209	35425	37925	40350	Net Plant ($mill)	46400
7.0%	6.2%	5.7%	5.9%	6.2%	6.5%	6.4%	5.6%	6.0%	5.5%	6.0%	5.5%	Return on Total Cap'l	5.5%
10.3%	9.4%	8.3%	8.8%	9.1%	9.6%	9.4%	8.5%	9.1%	8.5%	8.5%	8.5%	Return on Shr. Equity	8.5%
10.4%	9.5%	8.4%	8.9%	9.2%	9.6%	9.4%	8.5%	9.1%	8.5%	8.5%	8.5%	Return on Com Equity E	8.5%
3.9%	3.1%	2.5%	3.2%	3.1%	3.6%	3.6%	2.6%	3.5%	2.5%	3.0%	3.0%	Retained to Com Eq	3.0%
63%	67%	71%	65%	66%	62%	62%	69%	61%	67%	66%	65%	All Div'ds to Net Prof	65%

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	+.1	-1.1	+1.9
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	14883	13568	13721
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	385	366	370

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '20-'22
Revenues	--	-2.0%	.5%
"Cash Flow"	4.5%	4.5%	3.5%
Earnings	3.5%	3.0%	3.0%
Dividends	1.0%	1.5%	3.0%
Book Value	4.0%	3.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	3789	2911	3390	2829	12919
2015	3616	2788	3443	2707	12554
2016	3156	2794	3417	2633	12000
2017	3300	2800	3450	2800	12350
2018	3400	2900	3550	2900	12750

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	1.23	.63	1.49	.28	3.62
2015	1.26	.74	1.45	.60	4.05
2016	1.05	.78	1.48	.64	3.95
2017	1.20	.75	1.55	.65	4.15
2018	1.25	.78	1.60	.67	4.30

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.615	.615	.615	.615	2.46
2014	.63	.63	.63	.63	2.52
2015	.65	.65	.65	.65	2.60
2016	.67	.67	.67	.67	2.68
2017	.69				

BUSINESS: Consolidated Edison, Inc. is a holding company for Consolidated Edison Company of New York, Inc. (CECONY), which sells electricity, gas, and steam in most of New York City and Westchester County. Also owns Orange and Rockland Utilities (O&R), which operates in New York and New Jersey. Has 3.6 million electric, 1.2 million gas customers. Pursues competitive energy opportunities through three wholly owned subsidiaries. Entered into midstream gas joint venture 6/16. Purchases most of its power. Fuel costs: 30% of revenues. '15 reported depreciation rates: 3.0%-3.1%. Has 14,800 employees. Chairman, President & CEO: John McAvoy. Inc.: New York. Address: 4 Irving Place, New York, New York 10003. Tel.: 212-460-4600. Internet: www.conedison.com.

The New York State Public Service Commission has approved a regulatory settlement for Consolidated Edison's primary utility subsidiary. Consolidated Edison Company of New York's electric rates rose $194.6 million (2.6%) this year (retroactive to January 1st) and will increase $155.3 million (2.0%) in 2018 and $155.2 million (1.9%) in 2019. CECONY's gas rates were cut $5.4 million this year, but will rise $92.3 million (5.6%) in 2018 and $89.4 million (5.1%) in 2019. The utility will also benefit each year from amortizations to income of regulatory liabilities. The allowed return on equity is 9.0%, and the common-equity ratio is 48%.

The rate increases should help lift earnings this year and next. Another positive factor is ongoing conversions of oil-heat customers to gas heat. And for 2017, ConEd will have a full year of income from its midstream gas joint venture (completed in June of 2016). Note that the company was scheduled to report fourth-quarter results shortly after this report went to press. Note as well that our earnings presentation *includes* the effects of mark-to-market accounting gains or losses. These boosted the bottom line by $0.02 a share in the first nine months of 2016.

The board of directors raised the dividend in early 2017. As we had expected, the increase was $0.02 a share (3.0%) quarterly. ConEd is targeting a payout ratio in a range of 60%-70%.

ConEd has expanded its presence in renewable energy. The company is already among the top-10 owners of solar generating capacity in the United States. Last month, ConEd acquired Juhl Energy for an undisclosed amount. Juhl owns 36 megawatts of wind capacity and has a pipeline of projects totaling about 500 mw. The company also has an operating and maintenance services business. We think this will have a very small effect on the company's earning power until the pipeline of projects starts entering operation.

This timely and high-quality stock has a dividend yield that is close to the industry mean. However, with the recent price well within our 2020-2022 Target Price Range, total return potential is low.

Paul E. Debbas, CFA *February 17, 2017*

(A) Diluted EPS. Excl. nonrec. gains (losses): '02, (11¢); '03, (45¢); '13, (32¢); '14, 9¢; '16, 15¢; gain on discontinued operations: '08, $1.01. '14 EPS don't add due to rounding. Next earnings report due late April. (B) Div'ds historically paid in mid-Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '15: $29.74/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. for CECONY in '17: 9.0%; O&R in '15: 9.0%; earned on avg. com. eq., '15: 9.3%. Regulatory Climate: Below Average.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	45
Earnings Predictability	95

DOMINION RES. NYSE-D

RECENT PRICE	72.21	P/E RATIO	21.4 (Trailing: 21.0; Median: 18.0)	RELATIVE P/E RATIO	1.10	DIV'D YLD	4.2%	VALUE LINE

TIMELINESS 3 Lowered 11/18/16
SAFETY 2 Raised 9/11/98
TECHNICAL 3 Raised 1/13/17
BETA .70 (1.00 = Market)

2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+45%)	13%
Low	75	(+5%)	6%

Insider Decisions

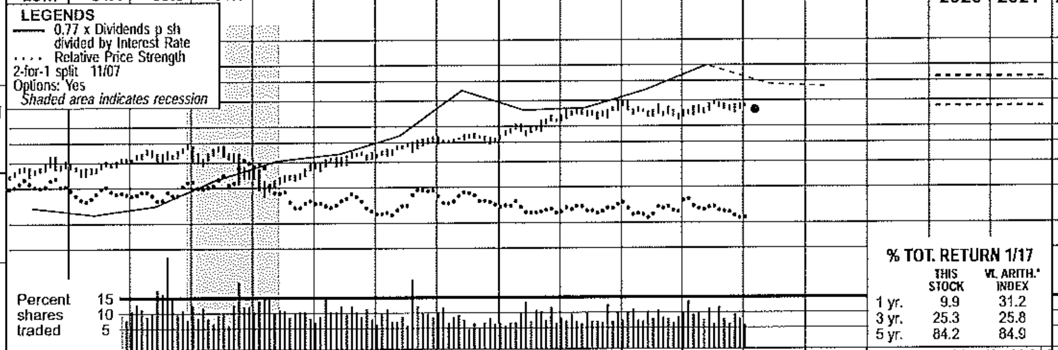
	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	4	0	0	0	1	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2016	2Q2016	3Q2016
to Buy	453	499	423
to Sell	369	314	377
Hld's(000)	395360	398528	406322

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
High:	42.2	49.4	48.5	39.8	45.1	53.6	55.6	68.0	80.9	79.9	79.0	77.0
Low:	34.4	39.8	31.3	27.1	36.1	42.1	48.9	51.9	63.1	64.5	66.3	70.9

Target Price Range
2020 | 2021 | 2022



% TOT. RETURN 1/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.9	31.2
3 yr.	25.3	25.8
5 yr.	84.2	84.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
19.94	16.58	18.57	20.54	25.96	23.61	27.17	27.93	25.24	26.17	25.24	22.73	22.56	21.25	19.59	18.70	19.35	19.90	Revenues per sh	22.50
3.92	4.45	3.97	4.18	3.70	4.91	5.08	5.07	4.82	5.11	5.04	5.24	5.47	5.71	5.98	6.35	6.75	7.40	"Cash Flow" per sh	9.00
1.49	2.41	1.96	2.13	1.50	2.40	2.13	3.04	2.64	2.89	2.76	2.75	3.09	3.05	3.20	3.44	3.40	3.80	Earnings per sh A	4.50
1.29	1.29	1.29	1.30	1.34	1.38	1.46	1.58	1.75	1.83	1.97	2.11	2.25	2.40	2.59	2.80	3.02	3.30	Div'd Decl'd per sh B ■	4.20
2.31	2.17	5.20	3.88	4.83	5.81	6.89	6.09	6.40	5.89	6.41	7.20	7.06	9.13	9.35	9.70	8.95	7.80	Cap'l Spending per sh	8.75
15.81	16.57	16.20	16.79	14.96	18.50	16.31	17.28	18.66	20.66	20.09	18.34	20.02	19.74	21.24	23.30	25.10	25.60	Book Value per sh C	24.25
529.40	616.20	650.40	680.40	695.00	698.00	576.80	583.20	599.40	580.80	569.70	576.10	581.50	585.30	596.30	627.00	643.50	643.50	Common Shs Outst'g D	615.00
20.9	12.0	15.2	15.1	24.9	16.0	20.6	13.8	12.7	14.3	17.3	18.9	19.2	23.0	22.1	21.3	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	20.0
1.07	.66	.87	.80	1.33	.86	1.09	.83	.85	.91	1.09	1.20	1.08	1.21	1.11	1.12			Relative P/E Ratio	1.25
4.1%	4.4%	4.3%	4.0%	3.6%	3.6%	3.3%	3.8%	5.2%	4.4%	4.1%	4.1%	3.8%	3.4%	3.7%	3.8%			Avg Ann'l Div'd Yield	4.7%
						15674	16290	15131	15197	14379	13093	13120	12436	11683	11733	12450	12800	Revenues ($mill)	13400
						1414.0	1781.0	1585.0	1724.0	1603.0	1594.0	1806.0	1793.0	1899.0	2212.0	2270	2575	Net Profit ($mill)	3580
						33.4%	37.1%	33.2%	38.6%	34.6%	36.2%	33.0%	28.1%	32.0%	22.8%	30.0%	30.0%	Income Tax Rate	25.0%
						7.3%	4.9%	4.8%	5.9%	5.3%	5.7%	3.7%	4.5%	5.3%	5.0%	3.0%	3.0%	AFUDC % to Net Profit	2.0%
						57.8%	59.1%	57.5%	56.3%	59.8%	60.9%	61.9%	65.4%	65.1%	67.5%	67.0%	66.0%	Long-Term Debt Ratio	61.5%
						41.1%	39.8%	41.5%	42.6%	39.3%	38.2%	37.3%	34.6%	34.9%	32.5%	33.0%	34.0%	Common Equity Ratio	38.5%
						22898	25290	26923	28012	29097	27676	31229	33360	36280	44835	48825	48100	Total Capital ($mill)	50700
						21352	23274	25592	26713	29670	30773	32628	36270	41554	49964	53550	56275	Net Plant ($mill)	64300
						8.0%	8.7%	7.5%	7.7%	7.0%	7.5%	7.3%	6.6%	6.5%	6.0%	6.0%	7.0%	Return on Total Cap'l	7.5%
						14.6%	17.2%	13.9%	14.1%	13.7%	14.7%	15.2%	15.5%	15.0%	14.5%	13.5%	15.0%	Return on Shr. Equity	19.0%
						14.9%	17.5%	14.0%	14.2%	13.9%	14.9%	15.4%	15.4%	15.0%	14.5%	13.5%	15.0%	Return on Com Equity E	19.0%
						5.0%	8.4%	4.7%	5.3%	4.0%	3.5%	4.2%	3.3%	2.9%	2.5%	1.5%	2.0%	Retained to Com Eq	1.5%
						67%	52%	67%	63%	71%	77%	73%	79%	81%	78%	85%	82%	All Div'ds to Net Prof	87%

CAPITAL STRUCTURE as of 9/30/16
Total Debt $34735 mill. Due in 5 Yrs $12383 mill.
LT Debt $28707 mill. LT Interest $1210 mill.
(LT interest earned: 3.8x)

Leases, Uncapitalized Annual rentals $67 mill.

Pension Assets-12/15 $6166 mill. Oblig $6391 mill.

Pfd Stock None

Common Stock 626,750,459 shs. as of 10/15/16
MARKET CAP: $45 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	+2.7	+1.6	+.7
Avg. Indust. Use (MWH)	14444	13847	13433
Avg. Indust. Revs. per KWH (¢)	6.00	6.12	6.17
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.9	+1.0	+.9
Fixed Charge Cov. (%)	339	266	352

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '20-'22
Revenues	-.5%	-4.5%	1.0%
"Cash Flow"	4.0%	2.5%	6.5%
Earnings	5.5%	1.5%	5.5%
Dividends	6.5%	7.0%	8.0%
Book Value	2.5%	1.5%	2.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	3630	2813	3050	2943	12436
2015	3409	2747	2971	2556	11683
2016	2921	2598	3132	3082	11733
2017	3400	2850	3150	3050	12450
2018	3500	2900	3250	3150	12800

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	1.03	.60	.95	.46	3.05
2015	.91	.70	1.00	.60	3.20
2016	.88	.73	1.10	.73	3.44
2017	.90	.75	1.00	.75	3.40
2018	1.00	.85	1.10	.85	3.80

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.5625	.5625	.5625	.5625	2.25
2014	.60	.60	.60	.60	2.40
2015	.6475	.6475	.6475	.6475	2.59
2016	.70	.70	.70	.70	2.80
2017	.755				

BUSINESS: Dominion Resources, Inc. is a holding company for Virginia Power & North Carolina Power, which serve 2.6 mill. customers in Virginia & northeastern North Carolina. Serves 2.3 mill. gas customers in Ohio, West Virginia, & Utah. Nonutility ops. incl. independent power production. Owns 70.9% of Dominion Midstream Partners. Acq'd Questar 9/16. Elec. rev. breakdown: residential, 46%; commercial, 32%; industrial, 7%; other, 15%. Generating sources: nuclear, 30%; coal, 26%; gas, 23%; other, 6%; purch., 15%. Fuel costs: 31% of revs. '15 reported depr. rates: 2.3%-3.7%. Has 14,700 employees. Chairman, Pres. & CEO: Thomas F. Farrell II. Inc.: VA. Address: 120 Tredegar St., P.O. Box 26532, Richmond, VA 23261-6532. Tel.: 804-819-2000. Internet: www.dom.com.

Dominion Resources' earnings guidance for 2017 disappointed Wall Street. By the company's definition, its "operating" earnings were $3.80 a share in 2016. (This excludes some expenses that we include in our presentation, which shows share net of $3.44.) Management's targeted "operating" range of profits for 2017 is $3.40-$3.90 a share. Among the negative factors expected this year are lower prices for power generated by the Millstone nonregulated nuclear plant in Connecticut, which will hurt earnings by an estimated $0.15-$0.20 a share; an additional refueling outage at Millstone; lower tax credits for solar investment (a negative factor of $0.20 a share); and an increase in average shares outstanding. As a result, we have slashed our earnings estimate by $0.60 a share, to $3.40. The stock reacted negatively to Dominion's announcement, falling 6% in price that day.

The company's bottom-line prospects for this year have not affected its dividend policy. In the first quarter, the board of directors raised the annual dividend $0.22 a share (7.9%). Beginning next year, Dominion is targeting growth of over 8% annually in the disbursement. The company's cash flow will benefit from the completion of the Cove Point liquefied natural gas export facility in late 2017, which Dominion will drop into its Dominion Midstream Partners master limited partnership. This enables the company to have a higher payout ratio than most utilities.

Dominion believes earnings will advance at least 10% in 2018. The biggest factor is Cove Point, which should contribute $0.40-$0.45 a share to the bottom line. We think the company can achieve this target (albeit off a lower base), and are estimating earnings of $3.80 a share. Weakness in the power markets, which affects Millstone, is a source of uncertainty, however. Beyond 2018, management's goal is annual profit growth of 6%-8% through 2020. The addition of a 1,588-megawatt, $1.3 billion gas-fired plant at Virginia Power in late 2018 should help in 2019. Dominion is also adding solar capacity and expanding its transmission system.

This stock offers a dividend yield and 3- to 5-year total return potential that exceed those of most utility issues.

Paul E. Debbas, CFA *February 17, 2017*

(A) Dil. egs. Excl. nonrec. gains (losses): '01, (42¢); '03, ($1.46); '04, (22¢); '06, (18¢); '07, $1.67; '08, 12¢; '09, (47¢); '10, $2.18; '11, (7¢); '12, ($1.70); '14, (76¢); losses from disc. ops.: '06, 26¢; '07, 1¢; '10, 26¢; '12, 4¢; '13, 16¢. '14 & '15 EPS don't add due to rounding. Next egs. due early May. (B) Div'ds histor. paid in mid-Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '15: $9.61/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost, adj. Rate all'd on com. eq. in '11: 10.9%; earn. on avg. com. eq., '15: 15.6%. Reg. Clim.: Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	85

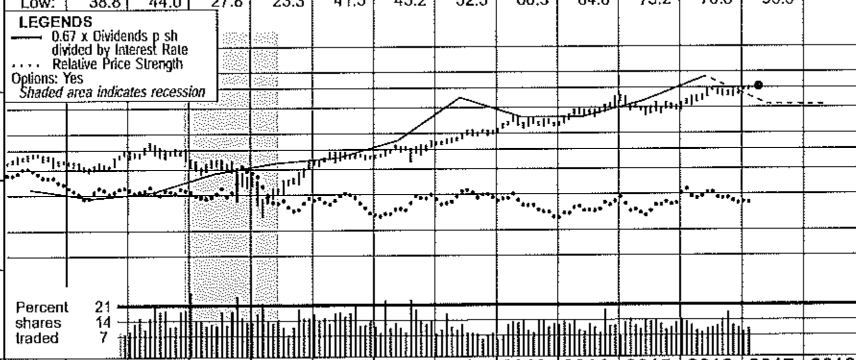
DTE ENERGY CO. NYSE-DTE

RECENT PRICE 101.55 | P/E RATIO 20.6 (Trailing: 21.1; Median: 16.0) | RELATIVE P/E RATIO 1.06 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 3 Lowered 11/4/16
SAFETY 2 Raised 12/21/12
TECHNICAL 3 Lowered 3/10/17
BETA .65 (1.00 = Market)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
High:	49.2	54.7	45.3	45.0	49.1	55.3	62.6	73.3	90.8	92.3	100.4	102.1
Low:	38.8	44.0	27.8	23.3	41.3	43.2	52.5	60.3	64.8	73.2	78.0	96.6

Target Price Range 2020 | 2021 | 2022



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	120	(+20%)	8%
Low	85	(-15%)	Nil

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	1	0	0	1	0	0	1	0	7
to Sell	1	1	0	1	0	0	2	2	0

Institutional Decisions

	2Q2016	3Q2016	4Q2016
to Buy	249	262	272
to Sell	205	196	244
Hld's(000)	117383	119482	123429

% TOT. RETURN 2/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	24.5	30.5
3 yr.	56.8	22.1
5 yr.	125.7	81.5

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
48.71	40.30	41.76	40.84	50.74	50.93	54.28	57.23	48.45	50.51	52.57	51.01	54.56	69.50	57.60	59.24	**64.05**	**67.70**	Revenues per sh	**75.50**
6.98	8.31	6.95	6.81	8.14	8.19	8.48	8.26	9.38	9.78	9.57	9.77	10.13	11.85	9.44	10.60	**11.60**	**12.45**	"Cash Flow" per sh	**14.75**
2.15	3.83	2.85	2.55	3.27	2.45	2.66	2.73	3.24	3.74	3.67	3.88	3.76	5.10	4.44	4.83	**5.30**	**5.65**	Earnings per sh A	**6.50**
2.06	2.06	2.06	2.06	2.06	2.08	2.12	2.12	2.12	2.18	2.32	2.42	2.59	2.69	2.84	3.06	**3.36**	**3.59**	Div'd Decl'd per sh B ■	**4.30**
6.80	5.88	4.45	5.19	5.99	7.92	7.96	8.42	6.26	6.49	8.77	10.56	10.59	11.58	11.26	11.40	**16.15**	**14.50**	Cap'l Spending per sh	**14.00**
28.48	27.26	31.36	31.85	32.44	33.02	35.86	36.77	37.96	39.67	41.41	42.78	44.73	47.05	48.88	50.22	**52.15**	**54.25**	Book Value per sh C	**62.00**
161.13	167.46	168.61	174.21	177.81	177.14	163.23	163.02	165.40	169.43	169.25	172.35	177.09	176.99	179.47	179.43	**179.50**	**179.50**	Common Shs Outst'g D	**187.00**
19.3	11.3	13.7	16.0	13.8	17.4	18.3	14.8	10.4	12.3	13.5	14.9	17.9	14.9	18.1	19.0	*Bold figures are*		Avg Ann'l P/E Ratio	**16.0**
.99	.62	.78	.85	.73	.94	.97	.89	.69	.78	.85	.95	1.01	.78	.91	1.00	*Value Line*		Relative P/E Ratio	**1.00**
5.0%	4.8%	5.3%	5.0%	4.6%	4.9%	4.4%	5.2%	6.3%	4.8%	4.7%	4.2%	3.8%	3.5%	3.5%	3.3%	*estimates*		Avg Ann'l Div'd Yield	**4.2%**

CAPITAL STRUCTURE as of 12/31/16
Total Debt $11782 mill. Due in 5 Yrs $3578 mill.
LT Debt $11269 mill. LT Interest $463 mill.
Incl. $7 mill. capitalized leases and $780 mill. Trust Preferred Securities.
(LT interest earned: 3.7x)

Leases, Uncapitalized Annual rentals $33 mill.
Pension Assets-12/16 $4012 mill. Oblig $5171 mill.

Pfd Stock None
Common Stock 179,432,999 shs. as of 1/31/17
MARKET CAP: $18 billion (Large Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
8861.0	9329.0	8014.0	8557.0	8897.0	8791.0	9661.0	12301	10337	10630	**11500**	**12150**	Revenues ($mill)	**14100**
453.0	445.0	532.0	630.0	624.0	666.0	661.0	905.0	796.0	868.0	**960**	**1020**	Net Profit ($mill)	**1240**
25.1%	34.9%	31.6%	32.7%	35.9%	29.8%	27.5%	28.5%	25.6%	24.5%	**26.0%**	**26.0%**	Income Tax Rate	**26.0%**
7.1%	11.2%	2.6%	1.6%	1.6%	3.0%	3.5%	4.1%	4.3%	3.6%	**4.0%**	**3.0%**	AFUDC % to Net Profit	**3.0%**
54.4%	56.4%	54.0%	51.3%	50.6%	48.8%	47.7%	50.0%	50.2%	55.6%	**56.0%**	**56.0%**	Long-Term Debt Ratio	**56.5%**
45.6%	43.6%	46.0%	48.7%	49.4%	51.2%	52.3%	50.0%	49.8%	44.4%	**44.0%**	**44.0%**	Common Equity Ratio	**43.5%**
12824	13736	13648	13811	14196	14387	15135	16670	17607	20280	**21375**	**22150**	Total Capital ($mill)	**26700**
11408	12231	12431	12992	13746	14684	15800	16820	18034	19730	**21500**	**22875**	Net Plant ($mill)	**26300**
5.3%	5.0%	5.7%	6.3%	5.9%	6.1%	5.7%	6.6%	5.7%	5.3%	**5.5%**	**6.0%**	Return on Total Cap'l	**6.0%**
7.7%	7.4%	8.5%	9.4%	8.9%	9.0%	8.3%	10.9%	9.1%	9.6%	**10.0%**	**10.5%**	Return on Shr. Equity	**10.5%**
7.7%	7.4%	8.5%	9.4%	8.9%	9.0%	8.3%	10.9%	9.1%	9.6%	**10.0%**	**10.5%**	Return on Com Equity E	**10.5%**
1.5%	1.7%	2.9%	4.0%	3.4%	3.5%	2.7%	5.2%	3.4%	3.7%	**4.0%**	**4.0%**	Retained to Com Eq	**3.5%**
80%	77%	65%	57%	62%	61%	67%	52%	63%	61%	**63%**	**63%**	All Div'ds to Net Prof	**65%**

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	-1.7	-.6	+3.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NMF	NMF	NMF
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	357	279	300

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	2.5%	4.0%	3.5%
"Cash Flow"	3.5%	2.0%	5.5%
Earnings	5.5%	6.0%	5.0%
Dividends	3.5%	5.5%	7.0%
Book Value	4.0%	4.0%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	3930	2698	2595	3078	12301
2015	2984	2268	2598	2487	10337
2016	2566	2262	2928	2874	10630
2017	**3050**	**2450**	**3000**	**3000**	**11500**
2018	**3250**	**2600**	**3150**	**3150**	**12150**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	1.84	.70	.88	1.68	5.10
2015	1.53	.61	1.47	.83	4.44
2016	1.37	.84	1.88	.73	4.83
2017	**1.60**	**1.00**	**1.60**	**1.10**	**5.30**
2018	**1.70**	**1.05**	**1.70**	**1.20**	**5.65**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.62	.62	.655	.655	2.55
2014	.655	.655	.655	.69	2.66
2015	.69	.69	.69	.73	2.80
2016	.73	.73	.73	.77	2.96
2017	.825				

BUSINESS: DTE Energy Company is a holding company for DTE Electric (formerly Detroit Edison), which supplies electricity in Detroit and a 7,600-square-mile area in southeastern Michigan, and DTE Gas (formerly Michigan Consolidated Gas). Customers: 2.1 mill. electric, 1.3 mill. gas. Has various nonutility operations. Electric revenue breakdown: residential, 48%; commercial, 34%; industrial, 13%; other, 5%. Generating sources: coal, 67%; nuclear, 17%; gas, 1%; purchased, 15%. Fuel costs: 52% of revenues. '16 reported deprec. rates: 3.5% electric, 2.4% gas. Has 10,000 employees. Chairman & CEO: Gerard M. Anderson. President & COO: Jerry Norcia. Inc.: MI. Address: One Energy Plaza, Detroit, MI 48226-1279. Tel.: 313-235-4000. Internet: www.dteenergy.com.

DTE Energy's utility subsidiaries have received rate orders in recent months. DTE Gas received an increase of $122.3 million, effective December 16th. DTE Electric was granted a raise of $184.3 million, effective February 7th. Each ruling was based on a 10.1% return on equity, based on a common-equity ratio of 52% and 50% for DTE Gas and DTE Electric, respectively. DTE Electric will file another application in the second quarter. As for DTE Gas, it expects to initiate its next case in 2018 or 2019.

We estimate that earnings will increase significantly in 2017. The comparison will be easy, as mark-to-market accounting charges associated with the energy trading business hurt the bottom line by $0.39 a share in 2016. Rate relief from the aforementioned tariff hikes will help. We expect a rise in income from the nonregulated side of DTE Energy's business, helped by a midstream gas acquisition the company made last fall. However, we also base our estimate on normal weather patterns. Favorable weather added $59 million to DTE Electric's net profit in 2016. Our 2017 earnings estimate is within the company's targeted range of $5.15-$5.46 a share.

The proposed NEXUS natural gas pipeline has had a temporary setback. The Federal Energy Regulatory Commission is currently unable to approve it due to a lack of a quorum, with three vacancies on the five-man commission. DTE Energy would have a 50% stake (a $1 billion investment) in NEXUS. The company believes the addition of a commissioner can still come in time for the project to be completed on schedule in late 2017.

We forecast higher profits in 2018. We assume that NEXUS is completed on schedule and that DTE Electric receives a rate increase in the first half of next year. The company's goal for annual earnings (and dividend) growth is 5%-7%.

DTE Energy's strengths are reflected in the stock price. The dividend yield is just average for a utility. And with the recent quotation near the midpoint of our 2020-2022 Target Price Range, total return potential is low, despite the strong dividend growth we project over that time frame.

Paul E. Debbas, CFA *March 17, 2017*

(A) Diluted EPS. Excl. nonrec. gains (losses): '03, (16¢); '05, (2¢); '06, 1¢; '07, $1.96; '08, 50¢; '11, 51¢; '15, (39¢); gains (losses) on disc. ops.: '03, 40¢; '04, (6¢); '05, (20¢); '06, (2¢); '07, $1.20; '08, 13¢; '12, (33¢). '16 EPS don't sum due to rounding. Next egs report due late Apr. (B) Div'ds paid in mid-Jan., Apr., July and Oct. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '16: $39.01/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '17: 10.1% elec.; in '16: 10.1% gas; earn. on avg. com. eq., '16: 4.9%. Reg. Clim.: Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	90

DUKE ENERGY NYSE-DUK

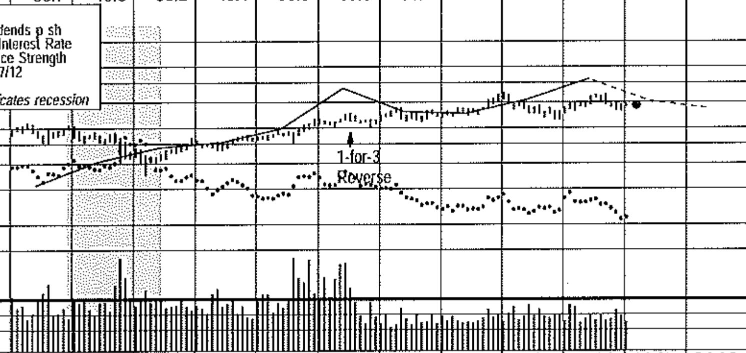
RECENT PRICE **77.57** | P/E RATIO **17.1** (Trailing: 18.6 / Median: NMF) | RELATIVE P/E RATIO **0.88** | DIV'D YLD **4.5%** | VALUE LINE

TIMELINESS **2** Lowered 1/20/17
SAFETY **2** New 6/1/07
TECHNICAL **4** Lowered 1/6/17
BETA .60 (1.00 = Market)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
High:	63.9	61.8	53.8	55.8	66.4	71.1	75.5	87.3	90.0	87.8	78.6
Low:	50.7	40.5	35.2	46.4	50.6	59.6	64.2	67.1	65.5	70.2	76.1

Target Price Range 2020 | 2021 | 2022

LEGENDS
—— 0.56 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
1-for-3 Rev split 7/12
Options: Yes
Shaded area indicates recession



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+30%)	10%
Low	75	(-5%)	4%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	1	0
Options	0	2	0	0	0	1	2	0	0
to Sell	0	1	0	0	1	0	0	1	0

Institutional Decisions

	1Q2016	2Q2016	3Q2016
to Buy	582	569	526
to Sell	404	433	465
Hld's(000)	405555	392385	388733

% TOT. RETURN 1/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	8.9	31.2
3 yr.	26.5	25.8
5 yr.	53.1	84.9

Duke Energy Corporation, in its current configuration, began trading on January 3, 2007, the day after it spun off its midstream gas operations into a new company, Spectra Energy (NYSE: SE). Duke Energy shareholders received half a share of Spectra Energy for each Duke share held. In July of 2012, Duke acquired Progress Energy and effected a 1-for-3 reverse split. Data for the "old" Duke are not shown because they are not comparable.

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
30.24	31.15	29.18	32.22	32.63	27.88	34.84	33.84	34.10	34.10	36.25	37.40	Revenues per sh	41.25
8.11	7.34	7.58	8.49	8.68	6.80	8.56	9.11	9.40	9.70	10.60	10.95	"Cash Flow" per sh	12.00
3.60	3.03	3.39	4.02	4.14	3.71	3.98	4.13	4.10	4.25	4.80	5.00	Earnings per sh A	5.50
2.58	2.70	2.82	2.91	2.97	3.03	3.09	3.15	3.24	3.36	3.48	3.60	Div'd Decl'd per sh B ■	3.96
7.43	10.35	9.85	10.84	9.80	7.81	7.83	7.62	9.83	13.40	12.55	12.55	Cap'l Spending per sh	12.50
50.40	49.51	49.85	50.84	51.14	58.04	58.54	57.81	57.74	58.70	60.00	61.40	Book Value per sh C	65.00
420.62	423.96	436.29	442.96	445.29	704.00	706.00	707.00	688.00	689.00	690.00	691.00	Common Shs Outst'g D	694.00
16.1	17.3	13.3	12.7	13.8	17.5	17.4	17.9	18.2	18.6	Bold figures are		Avg Ann'l P/E Ratio	16.0
.85	1.04	.89	.81	.87	1.11	.98	.94	.92	.95	Value Line		Relative P/E Ratio	1.00
4.4%	5.2%	6.2%	5.7%	5.2%	4.7%	4.4%	4.3%	4.3%	4.3%	estimates		Avg Ann'l Div'd Yield	4.5%
12720	13207	12731	14272	14529	19624	24598	23925	23459	23500	25000	25850	Revenues ($mill)	28550
1522.0	1279.0	1461.0	1765.0	1839.0	2136.0	2813.0	2934.0	2854.0	2940	3345	3495	Net Profit ($mill)	3920
31.9%	32.5%	34.4%	32.6%	31.3%	30.2%	32.6%	30.6%	32.2%	32.0%	32.0%	32.0%	Income Tax Rate	32.0%
7.2%	16.0%	17.5%	22.7%	23.2%	22.3%	8.8%	7.2%	9.2%	12.0%	10.0%	10.0%	AFUDC % to Net Profit	9.0%
30.9%	38.7%	42.6%	44.3%	45.1%	47.0%	48.0%	47.7%	48.6%	54.0%	54.5%	54.5%	Long-Term Debt Ratio	55.0%
69.1%	61.3%	57.4%	55.7%	54.9%	52.9%	52.0%	52.3%	51.4%	46.0%	45.5%	45.5%	Common Equity Ratio	45.0%
30697	34238	37863	40457	41451	77307	79482	78088	77222	88150	90600	93175	Total Capital ($mill)	101500
31110	34036	37950	40344	42661	68558	69490	70046	75709	85475	90200	94800	Net Plant ($mill)	107900
6.0%	4.8%	4.9%	5.5%	5.6%	3.6%	4.6%	4.8%	4.8%	4.5%	5.0%	5.0%	Return on Total Cap'l	5.0%
7.2%	6.1%	6.7%	7.8%	8.1%	5.2%	6.8%	7.2%	7.2%	7.5%	8.0%	8.0%	Return on Shr. Equity	8.5%
7.2%	6.1%	6.7%	7.8%	8.1%	5.2%	6.8%	7.2%	7.2%	7.5%	8.0%	8.0%	Return on Com Equity E	8.5%
2.0%	.6%	1.1%	2.1%	2.2%	.9%	1.5%	1.7%	1.5%	1.5%	2.5%	2.5%	Retained to Com Eq	2.5%
72%	89%	84%	73%	72%	82%	78%	76%	79%	79%	72%	71%	All Div'ds to Net Prof	70%

CAPITAL STRUCTURE as of 9/30/16
Total Debt $50176 mill. **Due in 5 Yrs** $15408 mill.
LT Debt $43964 mill. **LT Interest** $1978 mill.
Incl. $1336 mill. capitalized leases.
(LT interest earned: 3.0x)

Leases, Uncapitalized Annual rentals $219 mill.
Pension Assets-12/15 $8136 mill.
Oblig $7606 mill.

Pfd Stock None

Common Stock 688,941,372 shs.

MARKET CAP: $53 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	+1.3	+2.2	+.6
Avg. Indust. Use (MWH)	2687	2876	2883
Avg. Indust. Revs. per KWH (¢)	5.89	6.15	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+.8	+1.0	+1.2
Fixed Charge Cov. (%)	327	315	317

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '20-'22
Revenues	--	2.0%	3.5%
"Cash Flow"	--	3.0%	5.5%
Earnings	--	3.0%	5.0%
Dividends	--	2.5%	3.5%
Book Value	--	3.0%	2.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	6263	5708	6395	5559	23925
2015	6065	5589	6483	5322	23459
2016	5622	5484	6821	5573	23500
2017	6250	5900	6900	5950	25000
2018	6450	6100	7150	6150	25850

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	1.05	1.02	1.25	.81	4.13
2015	1.09	.87	1.44	.70	4.10
2016	1.00	.95	1.52	.78	4.25
2017	1.15	1.00	1.60	1.05	4.80
2018	1.20	1.05	1.65	1.10	5.00

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.765	.765	.78	.78	3.09
2014	.78	.78	.795	.795	3.15
2015	.795	.795	.825	.825	3.24
2016	.825	.825	.855	.855	3.36
2017					

BUSINESS: Duke Energy Corporation is a holding company for utilities with 7.4 mill. elec. customers in NC, FL, IN, SC, Oh, & KY, and 1.5 mill. gas customers in OH, KY, NC, SC, and TN. Owns independent power plants & has 25% stake in National Methanol in Saudi Arabia. Acq'd Progress Energy 7/12; Piedmont Natural Gas 10/16; discontinued most int'l ops. in '16. Elec. rev. breakdown: residential, 43%; commercial, 29%; industrial, 15%; other, 13%. Generating sources: coal, 29%; nuclear, 27%; gas, 23%; other, 1%; purchased, 20%. Fuel costs: 33% of revs. '15 reported deprec. rates: 2.6%-3.0%. Has 29,200 empls. Chairman, President & CEO: Lynn J. Good. Inc.: DE. Address: 550 South Tryon St., Charlotte, NC 28202-1803. Tel.: 704-382-3853. Web: www.duke-energy.com.

Duke Energy has completed the sale of most of its international operations. The company sold its Latin America businesses for $1.9 billion in cash. It used the proceeds to retire short-term debt. Duke prefers the relative stability of its domestic utilities to the greater volatility of the Latin America businesses. Duke isn't entirely out of international investments: It retains its 25% stake in National Methanol, a Saudi Arabia company.

The South Carolina commission approved a regulatory settlement. Duke's Progress Energy subsidiary received a $56 million (10.3%) rate increase, based on a 10.1% return on a 53% common-equity ratio. New tariffs took effect at the start of 2017. Duke's electric utilities in North Carolina have asked the regulators to defer certain costs for future recovery, and each expects to file rate applications this year.

We estimate that earnings will advance materially in 2017. The acquisition of Piedmont Natural Gas last fall should be accretive to earnings, especially since merger-related costs reduced profits by $0.28 a share in the first three quarters of 2016. (Duke was scheduled to report fourth-quarter results shortly after this report went to press.) We expect additional merger-related expenses this year as Piedmont is integrated, but these will probably be lower than in 2016. The aforementioned rate hike, along with modest growth at the utility operations, should be another plus. We forecast a decent, albeit smaller, earnings increase in 2018.

Some large projects are under way. In late 2017, Duke will add 750 megawatts of gas-fired capacity in South Carolina at a cost of $600 million. Two gas-fired units (1,640 mw) are being built in Florida at a cost of $1.5 billion, with in-service dates next year. Duke also has a stake in three gas pipelines, which together will represent an investment of about $3 billion.

Timely Duke stock offers an attractive dividend yield. The yield is a percentage point above the average for the electric utility industry. The earnings and dividend growth we project over the 3- to 5-year period should be enough to produce a long-term total return superior to that of most utilities.

Paul E. Debbas, CFA *February 17, 2017*

(A) Diluted EPS. Excl. nonrec. losses: '12, 70¢; '13, 24¢; '14, 67¢; '16, 21¢; gains (loss) on disc. ops.: '12, 6¢; '13, 2¢; '14, (80¢); '15, 5¢; '16, 18¢. Next earnings report due early May. (B) Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '15: $40.35/sh. (D) In mill., adj. for rev. split. (E) Rate base: Net orig. cost. Rates all'd on com. eq. in '13 in NC: 10.2%; in '17 in SC: 10.1%; in '09 in OH: 10.63%; in '04 in IN: 10.3%; earned on avg. com. eq., '15: 7.1%. Reg. Climate: NC Avg.; SC, OH, IN Above Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	85

EDISON INTERNAT'L NYSE-EIX

RECENT PRICE 72.51 | P/E RATIO 18.5 (Trailing: 18.7 Median: 12.0) | RELATIVE P/E RATIO 0.93 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS 3 Lowered 10/14/16

SAFETY 2 Raised 5/3/13

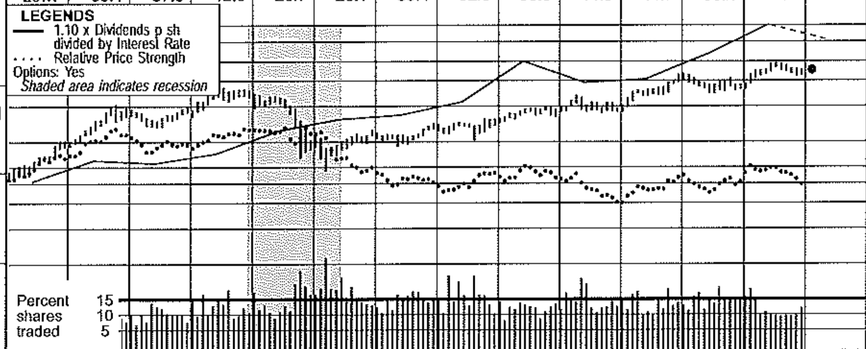
TECHNICAL 3 Lowered 12/30/16

BETA .65 (1.00 = Market)

High:	49.2	47.2	60.3	55.7	36.7	39.4	41.6	48.0	54.2	66.7	69.6	78.7	
Low:	30.4	37.9	42.8	26.7	23.1	30.4	32.6	39.6	44.3	44.7	55.2	58.0	

Target Price Range 2019 | 2020 | 2021

LEGENDS
— 1.10 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+25%)	8%
Low	65	(-10%)	1%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	1	0	0	0	0	0	0	0	0
Options	1	0	2	1	0	0	1	1	1
to Sell	2	0	1	1	0	0	3	0	1

Institutional Decisions

	1Q2016	2Q2016	3Q2016
to Buy	282	264	233
to Sell	231	246	251
Hld's(000)	269086	267229	263026

Percent shares traded 15 10 5

% TOT. RETURN 12/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	24.9	20.7
3 yr.	68.6	20.2
5 yr.	98.4	95.2

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
35.96	35.10	35.26	37.25	31.30	36.38	38.74	40.25	43.31	37.98	38.09	39.16	36.41	38.61	41.17	35.37	35.00	36.50	Revenues per sh	41.75
d.52	4.35	4.79	5.88	3.79	6.99	7.25	7.60	8.08	7.96	8.41	9.03	9.63	8.80	9.95	10.35	10.40	10.95	"Cash Flow" per sh	13.00
d5.84	1.30	1.82	2.38	.69	3.34	3.28	3.32	3.68	3.24	3.35	3.23	4.55	3.78	4.33	4.15	3.90	4.15	Earnings per sh A	5.00
.83	--	--	--	.80	1.02	1.10	1.18	1.23	1.25	1.27	1.29	1.31	1.37	1.46	1.73	1.98	2.21	Div'd Decl'd per sh B ■	2.70
4.57	2.86	4.88	3.95	5.32	5.73	7.78	8.67	8.67	10.07	13.94	14.76	12.73	11.05	11.99	12.97	11.55	13.75	Cap'l Spending per sh	15.00
7.43	10.04	13.62	16.52	18.57	20.30	23.66	25.92	29.21	30.20	32.44	30.86	28.95	30.50	33.64	34.89	36.70	38.50	Book Value per sh C	44.50
325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	Common Shs Outst'g D	325.81
--	10.0	7.8	7.0	NMF	11.7	13.0	16.0	12.4	9.7	10.3	11.8	9.7	12.7	13.0	14.8	18.1		Avg Ann'l P/E Ratio	15.0
--	.51	.43	.40	NMF	.62	.70	.85	.75	.65	.66	.74	.62	.71	.68	.75	.95		Relative P/E Ratio	.95
3.9%	--	--	--	3.1%	2.6%	2.6%	2.2%	2.7%	4.0%	3.7%	3.4%	3.0%	2.8%	2.6%	2.8%	2.8%		Avg Ann'l Div'd Yield	3.5%

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
12622	13113	14112	12374	12409	12760	11862	12581	13413	11524	11400	11900	Revenues ($mill)	13600
1134.0	1151.0	1266.0	1115.0	1153.0	1112.0	1594.0	1344.0	1539.0	1480.0	1415	1495	Net Profit ($mill)	1780
31.4%	27.3%	30.7%	33.0%	32.1%	25.7%	14.3%	25.2%	22.4%	6.6%	8.0%	25.0%	Income Tax Rate	25.0%
5.1%	8.2%	8.9%	10.5%	16.9%	14.8%	8.5%	7.8%	5.8%	8.0%	8.0%	8.0%	AFUDC % to Net Profit	6.0%
51.3%	49.1%	51.2%	49.3%	51.8%	55.3%	45.2%	45.7%	44.1%	45.0%	44.0%	45.0%	Long-Term Debt Ratio	45.0%
43.5%	46.0%	44.5%	46.5%	44.3%	40.6%	46.2%	46.2%	47.2%	46.7%	47.5%	46.5%	Common Equity Ratio	48.0%
17725	18375	21374	21185	23861	24773	20422	21516	23216	24352	25225	26900	Total Capital ($mill)	30400
15913	17403	18969	21966	24778	32116	30273	30455	32981	35085	36750	39025	Net Plant ($mill)	46800
8.6%	8.3%	7.4%	6.9%	6.3%	6.0%	8.9%	7.3%	7.7%	7.1%	6.5%	6.5%	Return on Total Cap'l	7.0%
13.1%	12.3%	12.1%	10.4%	10.0%	10.0%	14.2%	11.5%	11.9%	11.1%	10.0%	10.0%	Return on Shr. Equity	10.5%
14.0%	13.0%	12.8%	10.8%	10.4%	10.5%	15.9%	12.5%	13.0%	12.0%	11.0%	11.0%	Return on Com Equity E	11.5%
10.1%	9.2%	8.6%	6.7%	6.5%	6.3%	11.4%	8.1%	8.8%	7.2%	5.5%	5.0%	Retained to Com Eq	5.5%
31%	33%	35%	41%	40%	43%	32%	40%	37%	44%	54%	56%	All Div'ds to Net Prof	56%

CAPITAL STRUCTURE as of 9/30/16
Total Debt $12045 mill. Due in 5 Yrs $2360 mill.
LT Debt $10407 mill. LT Interest $468 mill.
(LT interest earned: 3.7x)
Leases, Uncapitalized Annual rentals $442 mill.
Pens. Assets-12/15 $3298 mill. Oblig. $4374 mill.
Pfd Stock $2191 mill. Pfd Div'd $113 mill.
4,800,198 sh. 4.08%-4.78%, $25 par, call. $25.50-$28.75/sh.; 3,250,000 sh. variable, noncum., call. $100; 1,250,000 sh. 6.5%, cum., $100 liq. value; 350,000 sh. 6.25%, $1000 liq. value; 460,012 sh. 5.1%-5.75%, $2500 liq. value.
Common Stock 325,811,206 shs. as of 10/28/16
MARKET CAP: $24 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	-.3	+2.1	-1.4
Avg. Indust. Use (MWH)	791	788	703
Avg. Indust. Revs. per KWH (¢)	8.00	8.86	9.07
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	22534	23055	23079
Annual Load Factor (%)	52.1	52.3	52.2
% Change Customers (yr-end)	+.6	+.6	+.6

Fixed Charge Cov. (%)	295	306	247

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	1.0%	-.5%	1.5%
"Cash Flow"	5.5%	3.5%	5.0%
Earnings	6.5%	3.5%	3.5%
Dividends	9.5%	4.0%	10.0%
Book Value	6.0%	1.5%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	2632	3046	3960	2943	12581
2014	2926	3016	4356	3115	13413
2015	2512	2908	3763	2341	11524
2016	2440	2777	3767	2416	11400
2017	2600	2850	3900	2550	11900

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.78	.78	1.41	.81	3.78
2014	.61	1.07	1.51	1.15	4.33
2015	.91	1.15	1.15	.94	4.15
2016	.82	.85	1.27	.96	3.90
2017	.85	.85	1.60	.85	4.15

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.337	.337	.337	.337	1.35
2014	.355	.355	.355	.355	1.42
2015	.418	.418	.418	.418	1.67
2016	.48	.48	.48	.48	1.92
2017	.5425				

BUSINESS: Edison International (formerly SCECorp) is a holding company for Southern California Edison Company (SCE), which supplies electricity to 4.9 mill. customers in a 50,000-sq.-mi. area in central, coastal, & southern CA (excl. Los Angeles & San Diego). Edison Energy is an energy svcs. co. Disc. Edison Mission Energy (independent power producer) in '12. Elec. rev. breakdown: residential, 37%; commercial, 44%; industrial, 6%; other, 13%. Generating sources: gas, 7%; nuclear, 7%; hydro, 1%; purchased, 85%. Fuel costs: 37% of revs. '15 reported depr. rate: 3.9%. Has 13,700 empls. Chairman: William P. Sullivan. Pres. & CEO: Pedro J. Pizzaro. Inc.: CA. Address: 2244 Walnut Grove Ave., P.O. Box 976, Rosemead, CA 91770. Tel.: 626-302-2222. Web: www.edison.com.

Edison International's utility subsidiary has a general rate case pending. Southern California Edison is seeking increases of $222 million (2.7%) in 2018 (plus $48 million to recover some deferred items); $533 million (4.2%) in 2019; and $570 million (5.2%) in 2020. The utility's capital budget for this three-year period is $15.1 billion. Most of these expenditures are traditional—the kind that have mostly been recovered in previous rate cases. But about $2.1 billion is for modernization of the electric grid. The California Public Utilities Commission (CPUC) has approved most of SCE's requested capital spending in recent rate orders, but because the grid modernization proposal is new, this might not happen in the current case. The utility would like a ruling by yearend, but even if this does not occur, new rates will be retroactive to the start of 2018.

The board of directors raised the annual dividend by $0.25 a share (13%). This was greater than we had estimated. The dividend will be paid on January 31st.

The CPUC has ordered the utility to meet with parties that want to reopen a regulatory settlement about a closed nuclear station. The CPUC's Office of Ratepayer Advocates and an intervenor group have complained about *ex parte* communications between SCE and former CPUC commissioners. Customers have been granted refunds and credits totaling almost $1.6 billion, but an additional refund is possible. The CPUC has set a deadline of April 28th to reach an agreement. If this does not happen, the CPUC will decide what to do next.

Earnings probably declined in 2016, but should recover this year. The company probably didn't book as many tax credits as in 2015. In addition, Edison's nonutility operations are experiencing start-up losses, estimated at $0.12 a share in 2016. In 2017, the utility's earning power will benefit from rate relief granted in SCE's previous general rate case as its rate base rises.

The dividend yield of this stock is below average for a utility. This reflects the company's above-average dividend growth potential. However, 3- to 5-year total return prospects are unspectacular.

Paul E. Debbas, CFA *January 27, 2017*

(A) Diluted EPS. Excl. nonrec. gains (losses): '02, $1.48; '03, (12¢); '04, $2.12; '09, (64¢); '10, 54¢; '11, ($3.33); '13, ($1.12); '15, ($1.18); gains (loss) from discont. ops.: '12, ($5.11); '13, 11¢; '14, 57¢; '15, 11¢. '14 EPS don't add due to rounding. Next earnings report due late Feb. (B) Div'ds paid late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '15: $23.06/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. in '15: 10.45%; earned on avg. com. eq., '15: 11.9%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	65

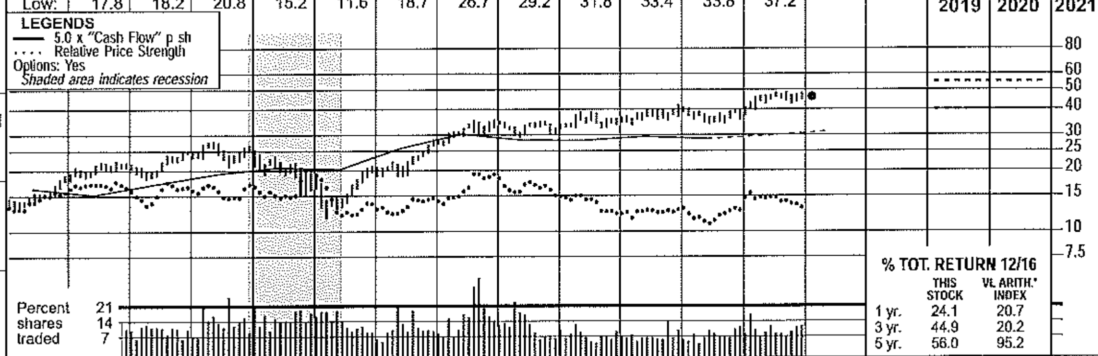
EL PASO ELECTRIC NYSE-EE

RECENT PRICE 46.30 | P/E RATIO 17.9 (Trailing: 20.4; Median: 15.0) | RELATIVE P/E RATIO 0.90 | DIV'D YLD 2.8% | VALUE LINE

TIMELINESS 3 Lowered 11/11/16
SAFETY 2 Raised 5/11/07
TECHNICAL 2 Raised 1/27/17
BETA .70 (1.00 = Market)

High:	22.4	25.0	28.2	25.5	21.1	28.7	35.7	35.3	39.1	42.2	41.3	48.8	
Low:	17.8	18.2	20.8	15.2	11.6	18.7	26.7	29.2	31.8	33.4	33.8	37.2	

LEGENDS
—— 5.0 x "Cash Flow" p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2019 | 2020 | 2021

2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+20%)	8%
Low	40	(-15%)	Nil

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	0	5	10	0	4	0	0	4	0
to Sell	0	0	1	0	0	0	0	0	0

Institutional Decisions

	1Q2016	2Q2016	3Q2016
to Buy	95	90	72
to Sell	68	75	90
Hld's(000)	39921	38927	39276

% TOT. RETURN 12/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	24.1	20.7
3 yr.	44.9	20.2
5 yr.	56.0	95.2

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
13.70	15.40	13.91	13.97	14.95	16.70	17.75	19.43	23.15	18.85	20.61	22.97	21.26	22.11	22.74	21.01	21.70	22.15	Revenues per sh	23.75
3.21	3.43	2.99	3.00	3.27	3.05	3.44	3.86	4.16	4.07	5.15	6.05	5.66	5.65	5.87	5.75	5.95	6.25	"Cash Flow" per sh	7.25
1.09	1.27	.57	.64	.69	.76	1.27	1.63	1.73	1.50	2.07	2.48	2.26	2.20	2.27	2.03	2.30	2.45	Earnings per sh A	2.75
--	--	--	--	--	--	--	--	--	--	--	.66	.97	1.05	1.11	1.17	1.23	1.30	Div'd Decl'd per sh B	1.65
1.70	1.85	1.75	2.03	1.94	2.28	2.73	4.63	5.36	5.95	5.27	5.90	6.70	7.18	8.50	8.55	7.00	5.75	Cap'l Spending per sh	7.00
8.05	9.01	9.20	10.51	11.23	11.56	12.60	14.76	15.47	16.45	19.04	19.03	20.57	23.44	24.39	25.13	26.15	27.25	Book Value per sh C	30.75
51.20	49.99	49.61	47.56	47.40	48.14	46.00	45.15	44.88	43.92	42.57	39.96	40.11	40.27	40.36	40.44	40.55	40.65	Common Shs Outst'g D	41.00
10.6	11.0	23.0	18.3	22.0	26.7	16.9	15.3	11.9	10.8	10.7	12.6	14.5	15.9	16.4	18.3	19.4		Avg Ann'l P/E Ratio	17.0
.69	.56	1.26	1.04	1.16	1.42	.91	.81	.72	.72	.68	.79	.92	.89	.86	.92	1.00		Relative P/E Ratio	1.05
--	--	--	--	--	--	--	--	--	--	--	2.1%	3.0%	3.0%	3.0%	3.1%	2.8%		Avg Ann'l Div'd Yield	3.5%

CAPITAL STRUCTURE as of 9/30/16
Total Debt $1333.7 mill. **Due in 5 Yrs** $183.5 mill.
LT Debt $1195.4 mill. **LT Interest** $72.3 mill.
(LT interest earned: 2.8x)

Pension Assets-12/15 $260.0 mill. **Oblig.** $325.7 mill.

Pfd Stock None

Common Stock 40,522,246 shs. as 10/31/16

MARKET CAP: $1.9 billion (Mid Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
816.5	877.4	1038.9	828.0	877.3	918.0	852.9	890.4	917.5	849.9	880	900	Revenues ($mill)	975
61.4	74.8	77.6	66.9	90.3	103.5	90.8	88.6	91.4	81.9	95.0	100	Net Profit ($mill)	120
29.8%	31.6%	32.8%	33.1%	36.1%	34.2%	34.1%	33.0%	31.0%	29.9%	36.0%	36.0%	Income Tax Rate	36.0%
8.0%	15.9%	20.4%	24.3%	22.1%	17.6%	22.4%	24.1%	30.8%	27.5%	17.0%	10.0%	AFUDC % to Net Profit	15.0%
51.5%	49.6%	53.8%	52.7%	51.2%	51.8%	54.8%	51.4%	53.5%	52.7%	55.0%	53.5%	Long-Term Debt Ratio	56.5%
48.5%	50.4%	46.2%	47.3%	48.8%	48.2%	45.2%	48.6%	46.5%	47.3%	45.0%	46.5%	Common Equity Ratio	43.5%
1195.8	1321.6	1503.9	1527.7	1660.1	1576.7	1824.5	1943.5	2118.4	2150.8	2345	2395	Total Capital ($mill)	2900
1332.2	1450.6	1595.6	1756.0	1865.8	1947.1	2102.3	2257.5	2488.4	2695.5	2830	2915	Net Plant ($mill)	3250
6.6%	7.1%	6.7%	6.0%	7.0%	8.3%	6.5%	6.1%	5.7%	5.3%	5.5%	6.0%	Return on Total Cap'l	5.5%
10.6%	11.2%	11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	8.1%	9.0%	9.0%	Return on Shr. Equity	9.5%
10.6%	11.2%	11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	8.1%	9.0%	9.0%	Return on Com Equity E	9.5%
10.6%	11.2%	11.2%	9.3%	11.1%	10.0%	6.3%	4.9%	4.8%	3.4%	4.0%	4.5%	Retained to Com Eq	4.0%
--	--	--	--	--	26%	43%	47%	49%	57%	53%	52%	All Div'ds to Net Prof	57%

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	+.4	-1.6	+2.3
Avg. Indust. Use (MWH)	21908	21505	21687
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	1852	1879	2055
Peak Load, Summer (Mw)	1750	1766	1794
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.3	+1.3	+1.4
Fixed Charge Cov. (%)	280	251	218

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	3.5%	1.0%	1.5%
"Cash Flow"	6.5%	5.0%	4.0%
Earnings	12.0%	4.0%	4.0%
Dividends	--	--	7.0%
Book Value	8.0%	7.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	177.3	240.1	282.7	190.3	890.4
2014	185.5	251.8	283.6	196.6	917.5
2015	163.8	219.5	289.7	176.9	849.9
2016	157.8	217.9	323.2	181.1	880
2017	170	230	305	195	900

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.19	.72	1.26	.03	2.20
2014	.11	.75	1.30	.10	2.27
2015	.09	.52	1.40	.02	2.03
2016	d.14	.55	1.84	.05	2.30
2017	.05	.65	1.60	.15	2.45

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.25	.265	.265	.265	1.05
2014	.265	.28	.28	.28	1.11
2015	.28	.295	.295	.295	1.17
2016	.295	.31	.31	.31	1.23
2017					

BUSINESS: El Paso Electric Company (EPE) provides electric service to 405,000 customers in an area of approximately 10,000 square miles in the Rio Grande valley in western Texas (68% of revenues) and southern New Mexico (19% of revenues), including El Paso, Texas and Las Cruces, New Mexico. Wholesale is 13% of revenues. Electric revenue breakdown by customer class not available. Generating sources: nuclear, 47%; gas, 34%; coal, 6%; purchased, 13%. Fuel costs: 28% of revenues. '15 reported depreciation rate: 2.6%. Has about 1,000 employees. Chairman: Charles A. Yamarone. President & CEO: Mary Kipp. Incorporated: Texas. Address: Stanton Tower, 100 North Stanton, El Paso, Texas 79901. Tel.: 915-543-5711. Internet: www.epelectric.com.

El Paso Electric Company will file two rate cases in the first half of 2017. The utility plans to put forth applications in Texas in the first quarter and in New Mexico in the second period. These petitions will seek to place Units 3 and 4 of a gas-fired generating station in the rate base. In 2016, EPE was granted tariff hikes in each state so that it can earn a return on Units 1 and 2, but the rate order in New Mexico was disappointing. (Since then, a new chairman of the New Mexico commission was voted into office.) Regulatory rulings are expected in Texas in the fourth quarter of 2017 and in New Mexico in the second quarter of 2018.

The company has refined its dividend policy. Previously, EPE targeted a payout ratio in the range of its peers, without specifying what it believes that range to be. However, in recent years this ratio has been below the utility norm. So, EPE wants its payout ratio to be in the 55%-65% range (without having depressed earnings, as in 2015) by 2020. Moreover, the company stated that it expects its annual increase in the second quarter to exceed the $0.06-a-share pace of the past four years (subject to the board's review of EPE's performance). We now estimate an $0.08-a-share (6.5%) hike in the annual disbursement in 2017.

Earnings will likely increase in 2017. The orders from the upcoming rate cases won't boost profits until 2018, but EPE will benefit from a full year's worth of the increases it was granted in 2016. Another positive factor is strong customer growth, exceeding 1% annually. The economy of the El Paso area is faring well, and is benefiting from trade with Mexico. (It remains to be seen whether the Trump Administration institutes trade policies that affect the service area's economy.) We have raised our 2017 share-net estimate by a dime, to $2.45, and forecast profit growth this year in a range of 6%-7%.

The dividend yield of this stock is nearly a percentage point below the utility average. The equity's valuation reflects the market's expectation of superior dividend growth. With the recent quotation near the midpoint of our 2019-2021 Target Price Range, total return potential is unexciting.

Paul E. Debbas, CFA *January 27, 2017*

(A) Diluted earnings. Excl. nonrecurring gains (losses): '01, (4¢); '03, 81¢; '04, 4¢; '05, (2¢); '06, 13¢; '10, 24¢. '14 earnings don't add to full-year total due to rounding. Next earnings report due late Feb. (B) Initial dividend declared 4/11; payment dates in late March, June, Sept., and Dec. (C) Incl. deferred charges. In '15: $115.1 mill., $2.85/sh. (D) In millions. (E) Rate allowed on common equity in TX in '12: none specified; in NM in '16: 9.48%; earned on avg. com. eq., '15: 8.2%. Regulatory Climate: TX, Average; NM, Below Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	70
Earnings Predictability	80

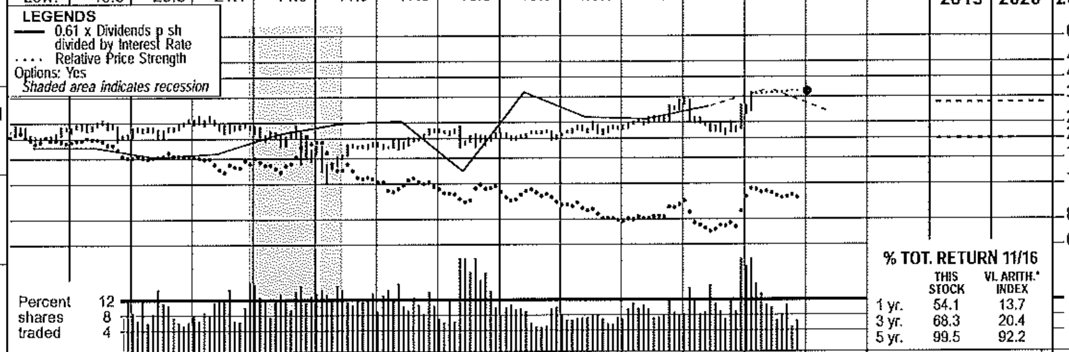
EMPIRE DISTRICT NYSE-EDE

RECENT PRICE 34.20 | P/E RATIO 23.8 (Trailing: 24.8 Median: 16.0) | RELATIVE P/E RATIO 1.22 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS — Suspended 2/19/16
SAFETY 2 Raised 3/23/12
TECHNICAL — Suspended 2/19/16
BETA .70 (1.00 = Market)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
High:	25.0	25.1	26.1	23.5	19.4	22.5	23.3	22.0	24.3	31.2	31.5	34.5
Low:	19.3	20.3	21.1	14.9	11.9	17.6	18.0	19.5	20.6	22.0	20.7	26.2

Target Price Range
2019 | 2020 | 2021



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(-10%)	1%
Low	20	(-40%)	-8%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	5	0	1	0	0	1	0	0	1
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2016	2Q2016	3Q2016
to Buy	76	66	56
to Sell	89	71	61
Hld's(000)	26980	28320	29209

% TOT. RETURN 11/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	54.1	13.7
3 yr.	68.3	20.4
5 yr.	99.5	92.2

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
14.78	13.37	13.56	13.03	12.67	14.80	13.67	14.59	15.25	13.04	13.02	13.74	13.11	13.81	15.00	13.82	*13.50*	*13.55*	Revenues per sh	*14.75*
3.12	2.19	2.43	2.48	2.22	2.45	2.75	2.69	2.91	2.72	2.85	3.21	2.99	3.14	3.45	3.32	*3.60*	*3.80*	"Cash Flow" per sh	*4.50*
1.35	.59	1.19	1.29	.86	.92	1.41	1.09	1.17	1.18	1.17	1.31	1.32	1.48	1.55	1.29	*1.40*	*1.45*	Earnings per sh A	*1.75*
1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	.64	1.00	1.01	1.03	1.04	*1.04*	*1.06*	Div'd Decl'd per sh B ■ †	*1.20*
7.61	4.02	3.43	2.65	1.64	2.83	3.97	5.46	6.28	4.07	2.63	2.44	3.22	3.60	4.91	4.23	*2.70*	*2.40*	Cap'l Spending per sh	*3.50*
13.65	13.58	14.59	15.17	14.76	15.08	15.49	16.04	15.56	15.75	15.82	16.53	16.90	17.43	18.02	18.32	*18.55*	*18.85*	Book Value per sh C	*20.25*
17.60	19.76	22.57	24.98	25.70	26.08	30.25	33.61	33.98	38.11	41.58	41.98	42.48	43.04	43.48	43.82	*44.50*	*45.00*	Common Shs Outst'g D	*46.50*
17.7	33.9	16.2	15.8	24.8	24.5	15.9	21.7	17.3	14.3	16.8	15.8	15.8	15.0	16.2	18.6	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*14.5*
1.15	1.74	.88	.90	1.31	1.30	.86	1.15	1.04	.95	1.07	.99	1.01	.84	.85	.93	*estimates*		Relative P/E Ratio	*.90*
5.4%	6.4%	6.6%	6.3%	6.0%	5.7%	5.7%	5.4%	6.3%	7.6%	6.5%	3.1%	4.8%	4.5%	4.1%	4.3%			Avg Ann'l Div'd Yield	*4.7%*
						413.5	490.2	518.2	497.2	541.3	576.9	557.1	594.3	652.3	605.6	*600*	*610*	Revenues ($mill)	*685*
						39.9	33.2	39.7	41.3	47.4	55.0	55.7	63.4	67.1	56.6	*60.0*	*65.0*	Net Profit ($mill)	*80.0*
						35.4%	30.3%	32.5%	32.5%	39.2%	38.4%	38.0%	37.1%	36.9%	37.4%	*37.5%*	*38.0%*	Income Tax Rate	*38.0%*
						10.7%	23.1%	31.5%	34.2%	21.5%	.9%	3.5%	9.4%	14.8%	13.6%	*8.0%*	*3.0%*	AFUDC % to Net Profit	*5.0%*
						49.7%	50.1%	53.6%	51.6%	51.3%	49.9%	49.1%	49.8%	50.6%	51.1%	*53.0%*	*50.0%*	Long-Term Debt Ratio	*50.5%*
						50.3%	49.9%	46.4%	48.4%	48.7%	50.1%	50.9%	50.2%	49.4%	48.9%	*47.0%*	*50.0%*	Common Equity Ratio	*49.5%*
						931.0	1081.1	1140.4	1240.3	1350.7	1386.2	1409.4	1493.6	1586.5	1640.7	*1765*	*1695*	Total Capital ($mill)	*1900*
						1031.0	1178.9	1342.8	1459.0	1519.1	1563.7	1657.6	1751.9	1910.3	2020.4	*2040*	*2045*	Net Plant ($mill)	*2175*
						5.9%	4.7%	5.2%	5.2%	5.1%	5.5%	5.4%	5.6%	5.5%	4.8%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.5%*
						8.5%	6.2%	7.5%	6.9%	7.2%	7.9%	7.8%	8.5%	8.6%	7.1%	*7.5%*	*7.5%*	Return on Shr. Equity	*8.5%*
						8.5%	6.2%	7.5%	6.9%	7.2%	7.9%	7.8%	8.5%	8.6%	7.1%	*7.5%*	*7.5%*	Return on Com Equity E	*8.5%*
						.8%	NMF	NMF	NMF	NMF	4.1%	1.9%	2.7%	2.9%	1.4%	*2.0%*	*2.0%*	Retained to Com Eq	*2.5%*
						90%	117%	109%	109%	110%	49%	76%	68%	66%	80%	*74%*	*73%*	All Div'ds to Net Prof	*69%*

CAPITAL STRUCTURE as of 9/30/16
Total Debt $854.9 mill. Due In 5 Yrs $216.8 mill.
LT Debt $829.6 mill. LT Interest $42.3 mill.
Incl. $3.3 mill. capitalized leases.
(LT interest earned: 3.0x)

Pension Assets-12/15 $186.9 mill. Oblig $243.7 mill.

Pfd Stock None

Common Stock 44,094,312 shs. as of 10/31/16

MARKET CAP: $1.5 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	+1.3	+1.3	-1.8
Avg. Industrial Use (MWH)	2943	2981	3024
Avg. Industrial Rev/KWH (¢)	7.93	8.21	8.28
Capacity at Peak (Mw)	1377	1326	1280
Peak Load, Summer (Mw)	1080	1162	1149
Annual Load Factor (%)	56.2	52.8	52.5
% Change Customers (avg.)	+.5	+.3	+.5
Fixed Charge Cov. (%)	331	334	291

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	.5%	.5%	.5%
"Cash Flow"	3.5%	3.0%	5.5%
Earnings	3.5%	4.0%	3.5%
Dividends	-2.0%	-4.5%	2.5%
Book Value	2.0%	2.5%	2.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	151.1	136.6	157.5	149.1	594.3
2014	179.7	149.8	171.5	151.3	652.3
2015	164.5	134.6	169.7	136.8	605.6
2016	151.3	139.3	175.4	*134*	*600*
2017	*160*	*140*	*175*	*135*	*610*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.30	.27	.56	.35	1.48
2014	.48	.26	.55	.26	1.55
2015	.34	.15	.58	.23	1.29
2016	.32	.21	.62	*.25*	*1.40*
2017	*.31*	*.26*	*.60*	*.28*	*1.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.25	.25	.25	.25	1.00
2013	.25	.25	.25	.255	1.01
2014	.255	.255	.255	.26	1.03
2015	.26	.26	.26	.26	1.04
2016	.26	.26	.26	.26	

BUSINESS: The Empire District Electric Company supplies electricity to 170,000 customers in a 10,000 sq. mi. area in southwestern Missouri (89% of retail elec. revs.), Kansas (5%), Oklahoma (3%), & Arkansas (3%). Acquired Missouri Gas (44,000 customers) 6/06. Supplies water service (4,000 customers) and has a small fiber-optics operation. Elec. rev. breakdown: residential, 42%; commercial, 31%; industrial, 16%; other, 11%. Generating sources: coal, 50%; gas, 27%; hydro, 1%; purch., 22%. Fuel costs: 31% of revenues. '15 reported depr. rate: 3.2%. Has about 750 employees. Chairman: D. Randy Laney. President & CEO: Bradley P. Beecher. Inc.: KS. Address: 602 S. Joplin Ave., P.O. Box 127, Joplin, MO 64802-0127. Tel.: 417-625-5100. Internet: www.empiredistrict.com.

It appears as if the acquisition of Empire District Electric Company will be completed soon. Algonquin Power & Utilities, a Canadian company that already has some operations in the United States under the Liberty Utilities name, has agreed to pay $34.00 in cash for each share of Empire District Electric. All shareholder and regulatory approvals have been received, except that of the Kansas Corporation Commission (KCC). However, the companies have reached a settlement with the KCC's staff. As part of the agreement, Empire District Electric would withdraw its pending request for a $6.4 million (25.7%) rate increase. Instead, the company would file for recovery of certain environmental costs through a rider on customers' bills. This would raise rates by $1.2 million. A ruling from the KCC is due by January 10, 2017. If the regulators approve the settlement—and there has been no significant opposition—the transaction is likely to be completed shortly thereafter. Accordingly, this might well be our last full-page report on Empire District Electric.

We advise stockholders to sell their shares on the open market. The recent price of Empire District Electric stock is *above* the buyout price. The Timeliness rank of this equity remains suspended due to the takeover agreement.

Empire District Electric received a rate increase in Missouri. The Missouri Public Service Commission approved a settlement calling for a hike of $20.4 million (4.5%), based on a return on equity in a range of 9.5%-9.9%. New tariffs took effect in mid-September.

We expect higher earnings this year and next, despite the inclusion of merger-related expenses. Merger-related costs are expected to reduce the bottom line by $0.10-$0.12 a share in 2016. Even so, we think profits will wind up higher for the year because the effects of regulatory lag hurt earnings in 2015. In addition, Empire District Electric should benefit from rate relief in 2016 and 2017. Note that we have raised our 2016 earnings estimate by $0.05 a share, to $1.40, because a hotter-than-normal summer helped boost the bottom line in the third quarter.

Paul E. Debbas, CFA *December 16, 2016*

(A) Diluted earnings. Excl. loss from discontinued operations: '06, 2¢. '15 EPS don't add due to rounding. Next earnings report due early Feb. (B) Div'ds historically paid in mid-Mar., June, Sept. and Dec. Div'ds suspended 3Q '11, reinstated 1Q '12. ■ Div'd reinvestment plan avail. (3% discount). † Shareholder investment plan avail. (C) Incl. intangibles. In '15: $5.88/sh. (D) In mill. (E) Rate base: Deprec. orig. cost. Rate allowed on com. eq. in MO in '16: 9.5%-9.9%; earned on avg. com. eq., '15: 7.2%. Regulatory Climate: Below Average.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	35
Earnings Predictability	85

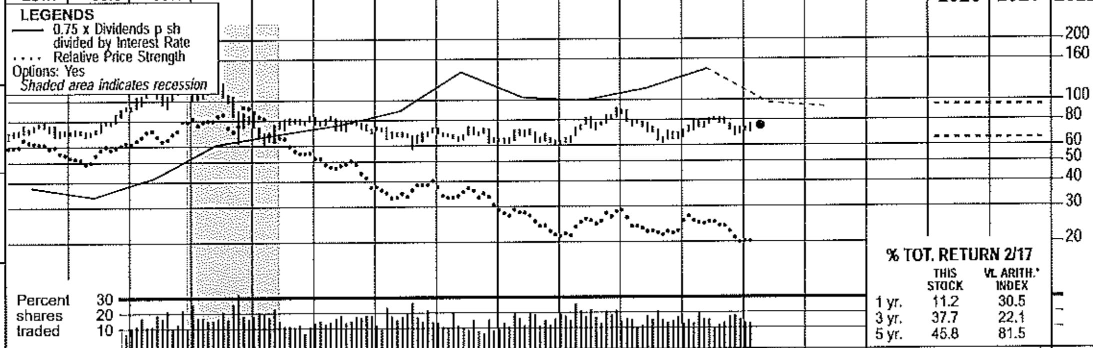
ENTERGY CORP. NYSE-ETR

RECENT PRICE	75.00	P/E RATIO	18.2 (Trailing: 10.9; Median: 12.0)	RELATIVE P/E RATIO	0.93	DIV'D YLD	4.7%	VALUE LINE

TIMELINESS **1** Raised 2/24/17
SAFETY **3** Lowered 3/22/13
TECHNICAL **5** Lowered 3/10/17
BETA .65 (1.00 = Market)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
High:	94.0	125.0	127.5	86.6	84.3	74.5	74.5	72.6	92.0	90.3	82.1	76.8
Low:	66.8	89.6	61.9	59.9	68.7	57.6	61.6	60.2	60.4	61.3	65.4	69.6

Target Price Range 2020 | 2021 | 2022



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+25%)	10%
Low	65	(-15%)	2%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	3	10	0	0	7	0	0	7	17
to Sell	4	0	0	3	0	0	0	0	0

Institutional Decisions

	2Q2016	3Q2016	4Q2016
to Buy	264	274	251
to Sell	219	219	271
Hld's(000)	153958	154079	160527

% TOT. RETURN 2/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	11.2	30.5
3 yr.	37.7	22.1
5 yr.	45.8	81.5

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
43.59	37.34	40.17	46.69	46.61	53.94	59.47	69.15	56.82	64.27	63.67	57.94	63.86	69.71	64.54	60.55	*59.50*	*61.15*	Revenues per sh	*58.75*
6.41	7.62	7.43	8.33	8.18	10.69	11.73	12.89	13.29	16.54	17.53	15.98	16.25	17.68	17.71	18.72	*17.20*	*17.70*	"Cash Flow" per sh	*19.00*
3.08	3.68	3.69	3.93	4.40	5.36	5.60	6.20	6.30	6.66	7.55	6.02	4.96	5.77	5.81	6.88	*4.85*	*5.00*	Earnings per sh A	*5.25*
1.28	1.34	1.60	1.89	2.16	2.16	2.58	3.00	3.00	3.24	3.32	3.32	3.32	3.32	3.34	3.42	*3.50*	*3.58*	Div'd Decl'd per sh B ■ †	*3.80*
6.25	6.88	6.85	6.51	6.72	9.44	10.29	13.92	12.99	13.33	15.21	18.18	15.73	14.82	16.79	17.28	*20.95*	*20.50*	Cap'l Spending per sh	*19.50*
33.78	35.24	38.02	38.26	35.71	40.45	40.71	42.07	45.54	47.53	50.81	51.73	54.00	55.83	51.89	45.12	*46.55*	*47.95*	Book Value per sh C	*52.00*
220.73	222.42	228.90	216.83	216.83	202.67	193.12	189.36	189.12	178.75	176.36	177.81	178.37	179.24	178.39	179.13	*179.00*	*179.00*	Common Shs Outst'g D	*179.00*
12.5	11.5	13.8	15.1	16.3	14.3	19.3	16.6	12.0	11.6	9.1	11.2	13.2	12.9	12.5	10.9	*Bold figures are*		Avg Ann'l P/E Ratio	*15.5*
.64	.63	.79	.80	.87	.77	1.02	1.00	.80	.74	.57	.71	.74	.68	.63	.57	*Value Line*		Relative P/E Ratio	*.95*
3.3%	3.2%	3.1%	3.2%	3.0%	2.8%	2.4%	2.9%	4.0%	4.2%	4.9%	4.9%	5.1%	4.5%	4.6%	4.6%	*estimates*		Avg Ann'l Div'd Yield	*4.7%*
						11484	13094	10746	11488	11229	10302	11391	12495	11513	10846	*10650*	*10950*	Revenues ($mill)	*10500*
						1160.0	1240.5	1251.1	1270.3	1367.4	1091.9	904.5	1060.0	1061.2	1249.8	*890*	*910*	Net Profit ($mill)	*955*
						30.7%	32.7%	33.6%	32.7%	17.3%	13.0%	26.7%	37.8%	2.2%	11.3%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
						5.8%	5.6%	7.4%	7.4%	8.9%	11.9%	10.1%	9.3%	7.4%	8.1%	*11.0%*	*11.0%*	AFUDC % to Net Profit	*9.0%*
						54.3%	58.2%	55.3%	56.3%	52.2%	55.8%	55.1%	54.9%	57.8%	63.6%	*62.5%*	*62.5%*	Long-Term Debt Ratio	*62.5%*
						43.9%	40.2%	43.1%	42.1%	46.4%	42.9%	43.6%	43.8%	40.8%	35.5%	*36.5%*	*36.5%*	Common Equity Ratio	*37.0%*
						17902	19795	19985	20166	19324	21432	22109	22842	22714	22777	*22700*	*23450*	Total Capital ($mill)	*25400*
						20974	22429	23389	23848	25609	27299	27882	28723	27824	27921	*29525*	*30975*	Net Plant ($mill)	*34300*
						7.9%	7.5%	7.6%	7.7%	8.5%	6.4%	5.4%	6.0%	6.0%	6.9%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.0%*
						14.2%	15.0%	14.0%	14.4%	14.8%	11.5%	9.1%	10.3%	11.1%	15.1%	*10.5%*	*10.5%*	Return on Shr. Equity	*10.0%*
						14.4%	15.3%	14.3%	14.7%	15.0%	11.6%	9.2%	10.4%	11.2%	15.2%	*10.5%*	*10.5%*	Return on Com Equity E	*10.0%*
						8.0%	8.1%	7.6%	7.6%	8.4%	5.2%	3.0%	4.4%	4.8%	7.7%	*3.0%*	*3.0%*	Retained to Com Eq	*3.0%*
						46%	48%	48%	49%	45%	56%	68%	58%	58%	50%	*72%*	*72%*	All Div'ds to Net Prof	*73%*

CAPITAL STRUCTURE as of 12/31/16
Total Debt $15275 mill. **Due in 5 Yrs** $4804.9 mill.
LT Debt $14492 mill. **LT Interest** $676.7 mill.
Incl. $697.5 mill. of securitization bonds.
(LT interest earned: 3.1x)
Leases, Uncapitalized Annual rentals $76.7 mill.
Pension Assets-12/16 $5171.2 mill.
Oblig $7142.6 mill.
Pfd Stock $203.2 mill. **Pfd Div'd** $14.1 mill.
825,105 sh. 4.32%-7.55%, $100 par; 250,000 sh. 8.75%, all without sinking fund.
Common Stock 179,394,698 shs.
as of 1/31/17
MARKET CAP: $13 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+2.9	+1.3	+.3
Avg. Indust. Use (MWH)	951	957	NA
Avg. Indust. Revs. per KWH(¢)	6.00	5.55	5.09
Capacity at Peak (Mw)	24367	24504	NA
Peak Load, Summer (Mw)	20472	21730	21387
Annual Load Factor (%)	65	61	NA
% Change Customers (yr-end)	+.6	+1.0	+.8
Fixed Charge Cov. (%)	309	223	258

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	3.0%	1.0%	*-1.5%*
"Cash Flow"	7.0%	2.5%	*1.0%*
Earnings	3.0%	-2.0%	*-2.5%*
Dividends	5.0%	1.0%	*2.0%*
Book Value	3.0%	1.0%	*.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	3208	2996	3458	2831	12494
2015	2920	2713	3371	2508	11513
2016	2609	2462	3124	2648	10845
2017	*2650*	*2500*	*3150*	*2350*	*10650*
2018	*2750*	*2550*	*3250*	*2400*	*10950*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	2.27	1.09	1.68	.74	5.77
2015	1.65	.83	1.90	1.43	5.81
2016	1.28	3.16	2.16	.28	6.88
2017	*1.25*	*1.05*	*1.55*	*1.00*	*4.85*
2018	*1.30*	*1.10*	*1.60*	*1.00*	*5.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.83	.83	.83	.83	3.32
2014	.83	.83	.83	.83	3.32
2015	.83	.83	.83	.85	3.34
2016	.85	.85	.85	.87	3.42
2017	.87				

BUSINESS: Entergy Corporation supplies electricity to 2.9 million customers through subsidiaries in Arkansas, Louisiana, Mississippi, Texas, and New Orleans (regulated separately from Louisiana). Distributes gas to 200,000 customers in Louisiana. Has a nonutility subsidiary that owns six nuclear units (one no longer operating). Electric revenue breakdown: residential, 37%; commercial, 27%; industrial, 26%; other, 10%. Generating sources: gas, 35%; nuclear, 31%; coal, 7%; purchased, 27%. Fuel costs: 28% of revenues. '16 reported depreciation rate: 2.8%. Has 13,600 employees. Chairman & CEO: Leo Denault. Incorporated: Delaware. Address: 639 Loyola Avenue, P.O. Box 61000, New Orleans, Louisiana 70161. Telephone: 504-576-4000. Internet: www.entergy.com.

Entergy is closing two more nuclear plants. In Michigan, the utility purchasing power from the Palisades nuclear plant agreed to buy out the contract (which will now expire in 2018, rather than 2022) because the price specified in the pact is higher than market prices. In New York, Entergy agreed to close the politically unpopular Indian Point station in 2020 and 2021, thereby resolving battles that had persisted for several years. As a result, Entergy took an after-tax charge of more than $1.8 billion in the fourth quarter of 2016. The company will continue to record costs associated with the plant closings, as it is for other facilities that it has announced will shut, but we *include* these in our earnings presentation due to their ongoing nature.

With these and other plant closings, and the sale of a unit in New York, Entergy will be almost an entirely regulated company by 2021. In recent years, low wholesale power prices and rising operating costs have hurt the company's nonregulated operations. (Revenues per megawatt-hour sold declined 15% in 2016.) This has forced Entergy to take some large nonrecurring charges to write down the value of its nonutility facilities, and, as mentioned above, the company is still incurring expenses associated with its decision to close these nuclear units.

A sizable earnings decline is likely this year. In 2016, Entergy benefited from tax credits that made its tax rate much lower than normal. In addition, the market conditions for the company's merchant power business remain unfavorable. Our estimate is near the lower end of Entergy's targeted range of $4.75-$5.35 a share because we include some expenses that it excludes from its guidance.

We forecast higher profits in 2018. Growth should come from the regulated side. Entergy's service territory is experiencing volume growth. In addition, the utilities benefit from formula rate plans that provide rate relief annually. We think higher utility income will outweigh weakness from the nonutility business.

This timely stock has one of the highest dividend yields of any electric utility issue. Total return potential to 2020-2022 is a bit above the industry average.

Paul E. Debbas, CFA *March 17, 2017*

(A) Diluted EPS. Excl. nonrec. gains (losses): '01, 15¢; '02, ($1.04); '03, 33¢ net; '05, (21¢); '12, ($1.26); '13, ($1.14); '14, (56¢); '15, ($6.99); '16, ($10.14). '14 EPS don't sum due to rounding. Next earnings report due early May. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. def'd charges. In '16: $34.32/sh. (D) In mill. (E) Rate base: Net orig. cost. Allowed ROE (blended): 10%; earned on avg. com. eq., '16: 12.8%. Ragulatory Climate: Avarage.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	15
Earnings Predictability	65

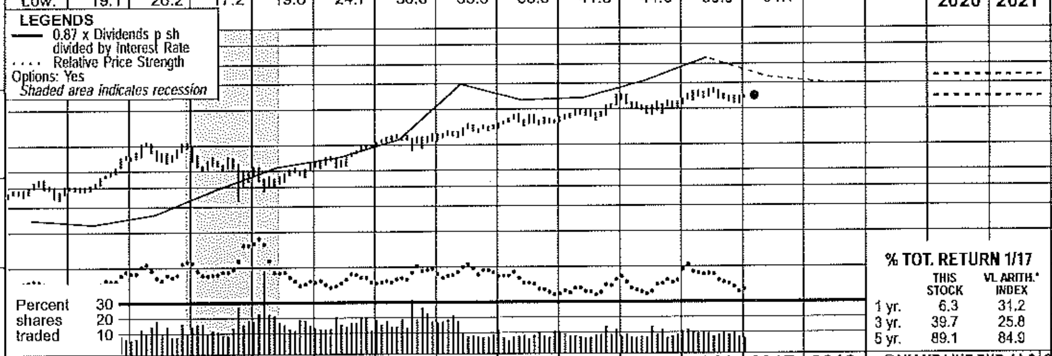
EVERSOURCE ENERGY NYSE-ES

RECENT PRICE 55.68 | P/E RATIO 17.6 (Trailing: 19.8; Median: 17.0) | RELATIVE P/E RATIO 0.91 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 3 Lowered 6/10/16
SAFETY 1 Raised 5/22/15
TECHNICAL 3 Raised 1/20/17
BETA .70 (1.00 = Market)

High:	28.9	33.6	31.6	26.5	32.2	36.5	40.9	45.7	56.7	56.8	60.4	56.1
Low:	19.1	26.2	17.2	19.0	24.7	30.0	33.5	38.6	41.3	44.6	50.0	54.1

Target Price Range 2020 | 2021 | 2022



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+25%)	9%
Low	55	(Nil)	3%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	1	0	0	0
Options	0	0	0	1	0	0	1	0	0
to Sell	0	0	0	0	0	1	0	1	0

Institutional Decisions

	1Q2016	2Q2016	3Q2016
to Buy	232	277	254
to Sell	246	205	226
Hld's(000)	225085	222452	219375

% TOT. RETURN 1/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.3	31.2
3 yr.	39.7	25.8
5 yr.	89.1	84.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
52.82	40.89	47.53	51.82	41.85	44.64	37.27	37.22	30.97	27.76	25.21	19.98	23.16	24.42	25.08	23.80	23.80	24.45	Revenues per sh	27.00
10.48	6.32	5.80	5.00	5.46	3.69	4.82	6.16	4.96	5.68	4.88	4.03	5.22	4.56	4.94	5.00	5.40	5.80	"Cash Flow" per sh	7.25
1.37	1.08	1.24	.91	.98	.82	1.59	1.86	1.91	2.10	2.22	1.89	2.49	2.58	2.76	2.95	3.15	3.35	Earnings per sh A	4.25
.45	.53	.58	.63	.68	.73	.78	.83	.95	1.03	1.10	1.32	1.47	1.57	1.67	1.78	1.90	2.00	Div'd Decl'd per sh B ■	2.30
3.40	3.86	4.31	4.85	5.89	5.49	7.14	8.06	5.17	5.41	6.08	4.69	4.62	5.06	5.44	7.00	8.40	7.75	Cap'l Spending per sh	6.50
16.27	17.33	17.73	17.80	18.46	18.14	18.65	19.38	20.37	21.60	22.65	29.41	30.49	31.47	32.64	33.80	35.10	36.45	Book Value per sh C	41.50
130.13	127.56	127.70	129.03	131.59	154.23	156.22	155.83	175.62	176.45	177.16	314.05	315.27	316.98	317.19	317.00	317.00	317.00	Common Shs Outst'g D	317.00
14.1	16.1	13.4	20.8	19.8	27.1	18.7	13.7	12.0	13.4	15.4	19.9	16.9	17.9	18.1	18.8	Bold figures are		Avg Ann'l P/E Ratio	14.5
.72	.88	.76	1.10	1.05	1.46	.99	.82	.80	.85	.97	1.27	.95	.94	.91	1.00	Value Line		Relative P/E Ratio	.90
2.3%	3.0%	3.5%	3.3%	3.5%	3.3%	2.6%	3.2%	4.2%	3.6%	3.2%	3.5%	3.5%	3.4%	3.3%	3.2%	estimates		Avg Ann'l Div'd Yield	3.7%

CAPITAL STRUCTURE as of 9/30/16
Total Debt $10344 mill. **Due in 5 Yrs** $4545.3 mill.
LT Debt $9235.1 mill. **LT Interest** $385.2 mill.
(LT interest earned: 4.6x)
Leases, Uncapitalized Annual rentals $16.4 mill.
Pension Assets-12/15 $3905.4 mill. Oblig $5080.1 mill.
Pfd Stock $155.6 mill. **Pfd Div'd** $7.6 mill.
Incl. 2,324,000 shs $1.90-$3.28 rates ($50 par) not subject to mandatory redemption, call. at $50.50-$54.00; 430,000 shs 4.25%-4.78% not subject to mandatory redemption, call. at $102.80-$103.63.
Common Stock 316,885,808 shs. as of 10/31/16
MARKET CAP: $18 billion (Large Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
5822.2	5800.1	5439.4	4898.2	4465.7	6273.8	7301.2	7741.9	7954.8	7550	7550	7750	Revenues ($mill)	8550
251.5	296.2	335.6	377.8	400.3	533.0	793.7	827.1	886.0	940	1010	1075	Net Profit ($mill)	1330
30.3%	29.7%	34.9%	36.6%	29.9%	34.0%	35.0%	36.2%	37.9%	37.5%	37.5%	37.5%	Income Tax Rate	37.5%
13.9%	15.8%	4.6%	7.1%	8.6%	2.3%	1.4%	2.4%	2.9%	4.0%	4.0%	4.0%	AFUDC % to Net Profit	3.0%
59.2%	60.4%	57.2%	55.1%	53.4%	43.7%	44.3%	45.9%	45.6%	46.5%	46.5%	46.5%	Long-Term Debt Ratio	45.5%
39.2%	38.1%	41.5%	43.6%	45.3%	55.4%	54.8%	53.2%	53.6%	53.0%	52.5%	52.5%	Common Equity Ratio	53.0%
7431.1	7926.2	8629.5	8741.8	8856.0	16675	17544	18738	19313	20250	21100	21950	Total Capital ($mill)	24400
7229.9	8207.9	8840.0	9567.7	10403	16605	17576	18647	19892	21600	23700	25550	Net Plant ($mill)	29200
5.0%	5.4%	5.4%	5.8%	5.9%	4.2%	5.5%	5.3%	5.5%	5.5%	5.5%	6.0%	Return on Total Cap'l	6.5%
8.3%	9.4%	9.1%	9.6%	9.7%	5.7%	8.1%	8.2%	8.4%	8.5%	9.0%	9.0%	Return on Shr. Equity	10.0%
8.4%	9.6%	9.2%	9.8%	9.8%	5.7%	8.2%	8.2%	8.5%	8.5%	9.0%	9.0%	Return on Com Equity E	10.0%
4.3%	5.3%	4.7%	5.0%	5.0%	1.6%	3.4%	3.5%	3.4%	3.5%	3.5%	3.5%	Retained to Com Eq	4.5%
50%	45%	50%	49%	50%	72%	59%	58%	61%	61%	60%	60%	All Div'ds to Net Prof	55%

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	+1.0	-1.6	+.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.02	6.14	5.86
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	427	426	447

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '20-'22
Revenues	-6.5%	-5.5%	1.5%
"Cash Flow"	-1.0%	-2.5%	5.5%
Earnings	9.5%	6.0%	7.0%
Dividends	9.5%	11.0%	5.5%
Book Value	6.0%	9.0%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	2290	1677	1892	1881	7741.9
2015	2513	1817	1933	1691	7954.8
2016	2056	1767	2040	1687	7550
2017	2150	1800	1900	1700	7550
2018	2200	1850	1950	1750	7750

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.74	.40	.74	.69	2.58
2015	.80	.65	.74	.57	2.76
2016	.77	.64	.83	.71	2.95
2017	.90	.70	.85	.70	3.15
2018	.95	.75	.90	.75	3.35

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.367	.367	.367	.367	1.47
2014	.393	.393	.393	.393	1.57
2015	.417	.417	.418	.418	1.67
2016	.445	.445	.445	.445	1.78
2017	.475				

BUSINESS: Eversource Energy (formerly Northeast Utilities) is the parent of utilities that have 3.1 million electric, 504,000 gas customers. Supplies power to most of Connecticut and gas to part of Connecticut; supplies power to three fourths of New Hampshire's population; supplies power to western Massachusetts and parts of eastern Massachusetts & gas to central & eastern Massachusetts. Acquired NSTAR 4/12. Electric revenue breakdown: residential, 52%; commercial, 36%; industrial, 5%; other, 7%. Fuel costs: 39% of revenues. '15 reported deprec. rate: 2.9%. Has 8,200 employees. Chairman: Thomas J. May. President & CEO: Jim Judge. Inc.: Massachusetts. Address: 300 Cadwell Drive, Springfield, MA 01104. Tel.: 413-785-5871. Internet: www.eversource.com.

Eversource's utilities in eastern and western Massachusetts are seeking electric rate increases. The utilities filed for a total raise of $96 million, based on a 10.5% return on a 53.3% common-equity ratio. Eversource also wants to combine the two utilities into one entity. New rates will take effect at the start of 2018.

An electric rate case is upcoming in Connecticut. Eversource plans to put forth an application at the start of June, with new tariffs going into effect at the beginning of December.

We estimate solid earnings growth in 2017 and 2018. Eversource benefits from annual investments in electric transmission. Reductions in operating and maintenance expenses are another plus, as are customer conversions from oil heat to gas heat. Rate relief from the aforementioned rate cases should help next year. Our estimates would produce annual profit growth within management's targeted range of 5%-7%.

Eversource is trying to overcome opposition to two major proposed projects. The company has a 40% stake in a $3 billion pipeline to provide a much-needed increase in the gas supply to New England. The Massachusetts Supreme Court ruled that state law prohibits utilities from billing electric customers for pipelines. The original in-service date in 2018 probably won't be met. Also, Eversource wants to build a $1.6 billion transmission line between New Hampshire and Quebec. This project has been delayed, and the projected in-service date is now late 2019.

The board of directors raised the dividend. The increase in the quarterly payout was $0.03 a share (6.7%). Eversource's goal for annual dividend growth is 5%-7%, the same as for earnings growth.

The Massachusetts utilities received permission to build solar capacity. They will construct 62 megawatts this year at an expected cost of $180 million-$200 million.

High-quality Eversource stock has a dividend yield that is about average for a utility. Total return potential to 2020-2022 is also close to the norm for this industry.

Paul E. Debbas, CFA *February 17, 2017*

(A) Dil. EPS. Excl. nonrec. gains (losses): '02, 10¢; '03, (32¢); '04, (7¢); '05, ($1.36); '08, (19¢); '10, 9¢. '13 & '14 EPS don't add due to rounding. Next earnings report due late Feb. (B) Div'ds historically paid late Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '15: $22.88/sh. (D) In mill. (E) Rate all'd on com. eq. in MA: (elec) '11, 9.6%; (gas) '16, 9.8%; in CT: (elec.) '15, 9.02%; (gas) '15, 9.5%; in NH: '10, 9.67%; earn. on avg. com. eq., '15: 8.7%. Regul. Clim.: CT, Below Avg.; NH, Avg.; MA, Above Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	80
Earnings Predictability	85

EXELON CORP. NYSE-EXC

RECENT PRICE **35.81** | P/E RATIO **14.0** (Trailing: 20.0; Median: 15.0) | RELATIVE P/E RATIO **0.72** | DIV'D YLD **3.7%** | VALUE LINE

TIMELINESS 1 Raised 12/30/16

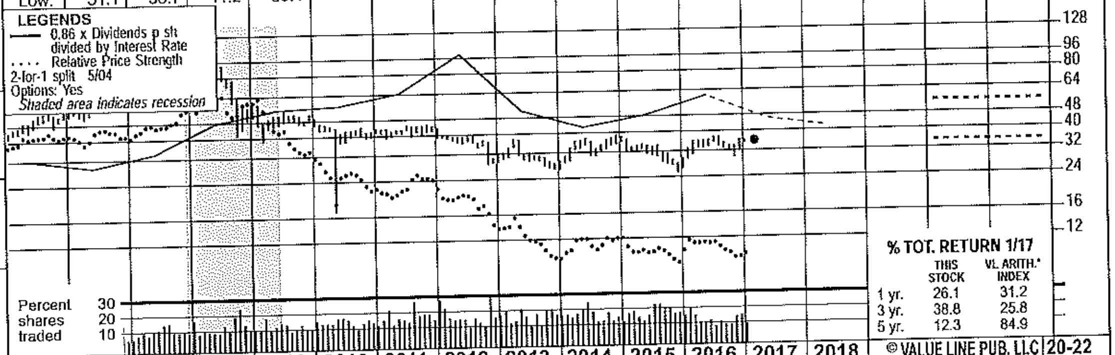
SAFETY 3 Lowered 11/23/12

TECHNICAL 3 Raised 1/6/17

BETA .70 (1.00 = Market)

High:	63.6	86.8	92.1	59.0	49.9	45.4	43.7	37.8	38.9	38.3	37.7	36.2
Low:	51.1	58.7	41.2	38.4	17.0	39.1	28.4	26.6	26.5	25.1	26.3	34.8

LEGENDS
— 0.86 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 5/04
Options: Yes
Shaded area indicates recession



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+55%)	*14%*
Low	35	(Nil)	*4%*

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	0	0	0	0	0	1	1
to Sell	0	1	0	1	0	1	0	0	1

Institutional Decisions

	1Q2016	2Q2016	3Q2016
to Buy	375	351	337
to Sell	317	343	336
Hld's(000)	702696	687169	679803

% TOT. RETURN 1/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	26.1	31.2
3 yr.	38.8	25.8
5 yr.	12.3	84.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
23.58	23.13	24.09	21.85	23.05	23.37	28.62	28.65	26.25	28.17	28.53	27.48	29.03	31.90	32.01	*33.90*	*33.10*	*34.15*	Revenues per sh	*37.00*
5.06	5.03	5.06	5.68	6.19	6.71	7.43	7.64	8.25	8.32	7.23	6.61	6.72	6.61	6.80	*7.85*	*8.70*	*9.05*	"Cash Flow" per sh	*10.00*
2.20	2.40	2.44	2.75	3.21	3.50	4.03	4.10	4.29	3.87	3.75	1.92	2.31	2.10	2.54	1.80	*2.65*	*2.80*	Earnings per sh A	*3.50*
.91	.88	.96	1.26	1.60	1.64	1.82	2.05	2.10	2.10	2.10	2.10	1.46	1.24	1.24	1.26	*1.29*	*1.32*	Div'd Decl'd per sh B ■	*1.70*
3.18	3.33	2.98	2.89	3.25	3.61	4.05	4.74	4.96	5.03	6.09	6.77	6.29	7.07	8.29	*9.25*	*7.35*	*6.40*	Cap'l Spending per sh	*5.75*
12.82	11.97	12.95	14.19	13.69	14.89	15.34	16.78	19.16	20.49	21.68	25.07	26.52	26.29	28.04	*27.90*	*29.60*	*31.55*	Book Value per sh C	*36.75*
642.01	646.63	656.37	664.19	666.37	669.86	660.88	658.15	659.76	661.85	663.37	854.78	857.29	859.83	919.92	*925.00*	*956.00*	*959.00*	Common Shs Outst'g D	*968.00*
13.2	10.5	11.8	13.0	15.4	16.5	18.2	18.0	11.5	11.0	11.3	19.1	13.4	16.0	12.6	18.7	*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
.68	.57	.67	.69	.82	.89	.97	1.08	.77	.70	.71	1.22	.75	.84	.63	.98	*Value Line*		Relative P/E Ratio	*.80*
3.1%	3.5%	3.4%	3.5%	3.2%	2.8%	2.5%	2.8%	4.3%	4.9%	5.0%	5.7%	4.7%	3.7%	3.9%	3.7%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*
						18916	18859	17318	18644	18924	23489	24888	27429	29447	31360	*31650*	*32750*	Revenues ($mill)	*35750*
						2730.0	2721.0	2844.0	2567.0	2499.0	1579.0	1999.0	1826.0	2282.0	1739.0	*2500*	*2865*	Net Profit ($mill)	*3330*
						34.6%	32.6%	38.8%	39.2%	36.8%	32.4%	36.5%	27.2%	32.2%	*38.0%*	*33.0%*	*33.0%*	Income Tax Rate	*33.0%*
						1.8%	1.3%	2.3%	2.1%	3.0%	5.8%	4.5%	5.5%	5.4%	*6.0%*	*4.0%*	*3.0%*	AFUDC % to Net Profit	*3.0%*
						53.9%	53.1%	47.2%	46.8%	45.7%	45.8%	44.4%	46.7%	48.3%	*55.5%*	*54.5%*	*51.5%*	Long-Term Debt Ratio	*50.0%*
						45.7%	46.6%	52.4%	52.9%	54.0%	53.5%	55.2%	52.8%	51.3%	*44.5%*	*45.5%*	*48.5%*	Common Equity Ratio	*50.0%*
						22189	23726	24112	25651	26661	40057	41196	42811	50272	*58000*	*62075*	*62475*	Total Capital ($mill)	*71100*
						24153	25813	27341	29941	32570	45186	47330	52087	57439	71555	*73300*	*74625*	Net Plant ($mill)	*74500*
						14.1%	13.1%	13.3%	11.4%	10.6%	5.1%	5.9%	5.3%	5.5%	*4.0%*	*5.0%*	*5.5%*	Return on Total Cap'l	*6.0%*
						26.7%	24.4%	22.3%	18.8%	17.3%	7.3%	8.7%	8.0%	8.8%	*6.5%*	*9.0%*	*9.5%*	Return on Shr. Equity	*9.5%*
						26.9%	24.6%	22.5%	18.9%	17.3%	7.3%	8.7%	8.0%	8.8%	*6.5%*	*9.0%*	*9.5%*	Return on Com Equity E	*9.5%*
						15.3%	12.5%	11.5%	8.7%	7.7%	NMF	3.2%	3.3%	4.5%	*2.0%*	*4.5%*	*5.5%*	Retained to Com Eq	*4.5%*
						43%	49%	49%	54%	56%	109%	63%	59%	49%	*68%*	*49%*	*44%*	All Div'ds to Net Prof	*49%*

CAPITAL STRUCTURE as of 9/30/16
Total Debt $36051 mill. **Due in 5 Yrs** $12658 mill.
LT Debt $32972 mill. **LT Interest** $1273 mill.
Includes $642 mill. nonrecourse transition bonds.
(LT interest earned: 4.1x)
Leases, Uncapitalized Annual rentals $133 mill.

Pension Assets-12/15 $14347 mill.
Oblig $17753 mill.

Pfd Stock None

Common Stock 923,270,314 shs.

MARKET CAP: $33 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	-.5	-.7	-1.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NMF	NMF	NMF
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Nuclear Capacity Factor (%)	94.1	94.3	NA
% Change Customers (yr-end)	+.6	+.6	+1.1
Fixed Charge Cov. (%)	338	263	367

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '20-'22
Revenues	3.0%	2.5%	*2.5%*
"Cash Flow"	1.5%	-3.5%	*6.0%*
Earnings	-2.0%	-10.5%	*5.0%*
Dividends	0.5%	-9.0%	*4.0%*
Book Value	7.0%	7.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	7237	6024	6912	7256	27429
2015	8830	6514	7401	6702	29447
2016	7573	6910	9002	7875	31360
2017	*7950*	*7100*	*8800*	*7800*	*31650*
2018	*8350*	*7400*	*9000*	*8000*	*32750*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.10	.68	.96	.35	2.10
2015	.80	.74	.69	.33	2.54
2016	.26	.45	.76	.32	1.80
2017	*.70*	*.66*	*.87*	*.42*	*2.65*
2018	*.74*	*.70*	*.90*	*.46*	*2.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.525	.31	.31	.31	1.46
2014	.31	.31	.31	.31	1.24
2015	.31	.31	.31	.31	1.24
2016	.31	.318	.318	.318	1.26
2017					

BUSINESS: Exelon Corporation is a holding company for Commonwealth Edison, PECO Energy, Baltimore Gas and Electric, Pepco, Delmarva Power, & Atlantic City Electric. Has 8.6 mill. elec., 1.3 mill. gas customers. Has nonregulated generating & energy-marketing ops. Acq'd Constellation Energy 3/12; Pepco Holdings 3/16. Elec. rev. breakdown: res'l, 63%; small comm'l & ind'l, 23%; large comm'l & ind'l, 13%; other, 1%. Generating sources: nuclear, 68%; other, 8%; purch., 24%. Fuel costs: 44% of revs. '15 depr. rates: 2.8%-3.5% elec., 2.2% gas. Has 34,000 empls. Chairman: Mayo A. Shattuck III. Pres. & CEO: Christopher M. Crane. Inc.: PA. Address: 10 S. Dearborn St., P.O. Box 805379, Chicago, IL 60680-5379. Tel.: 312-394-7398. Internet: www.exeloncorp.com.

Exelon will benefit from a new law in Illinois. Low electric prices (a result of low prices of natural gas) and subsidies for wind power had made the company's nuclear plants in the state unprofitable, so management had intended to shut the three units unless a law was passed that would provide subsidies to them. This law will take effect at the start of June. Despite this, we have cut our 2017 earnings estimate by $0.15 a share, to $2.65, because unfavorable conditions in the power markets are affecting the rest of Exelon's merchant generating units.

A similar law in New York is facing legal challenges. Another company, Entergy, had planned to shut a nuclear unit there until the law was enacted. Instead, Exelon will buy the 838-megawatt facility for $110 million. The new law will boost Exelon's profits by $0.08-$0.10 a share, and the plant purchase will contribute another $0.02-$0.08—provided the legal challenges are decided in the company's favor.

The enactment of these laws shows that conditions in the power markets are unfavorable for owners of merchant generating plants. This has persisted since early this decade, and explains why Exelon's profits are well below their level several years ago. This also explains why the company has placed increased emphasis on its regulated utility business in recent years, most notably by acquiring Pepco Holdings last March. Costs associated with this purchase hurt the bottom line in 2016.

The utilities that came with the Pepco purchase are awaiting rate orders. They are underearning their allowed returns on equity by a wide margin. Pepco is seeking an $82.1 million increase in Washington, DC. Delmarva requested electric and gas raises of $62.8 million and $21.5 million, respectively, in Delaware and an electric boost of $57.0 million in Maryland. Each application is based on a 10.6% ROE. Rate relief should benefit earnings this year and next.

This timely stock has a dividend yield that is about equal to the utility average. We think dividend growth will accelerate over the 3- to 5-year period, thanks to a low payout ratio. This should produce a respectable long-term total return.

Paul E. Debbas, CFA *February 17, 2017*

(A) Diluted egs. Excl. nonrec. gain (losses): '03, ($1.06); '05, ($1.85); '06, ($1.15); '09, (20¢); '12, (50¢); '13, (31¢); '14, 23¢; '16, (58¢). '14-'16 EPS don't add due to rounding or chg. in shs. Next egs. report due early May. (B) Div'ds paid in early Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '15: $10.02/sh. (D) In mill., adj. for split. (E) Rate all'd on com. eq. in IL in '15: 9.25%; in MD in '16: 9.75% elec., 9.65% gas; in NJ in '16: 9.75%; earn. on avg. com. eq., '15: 9.4%. Reg. Clim.: PA, NJ Avg.; IL, MD, Below Avg.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	5
Earnings Predictability	60

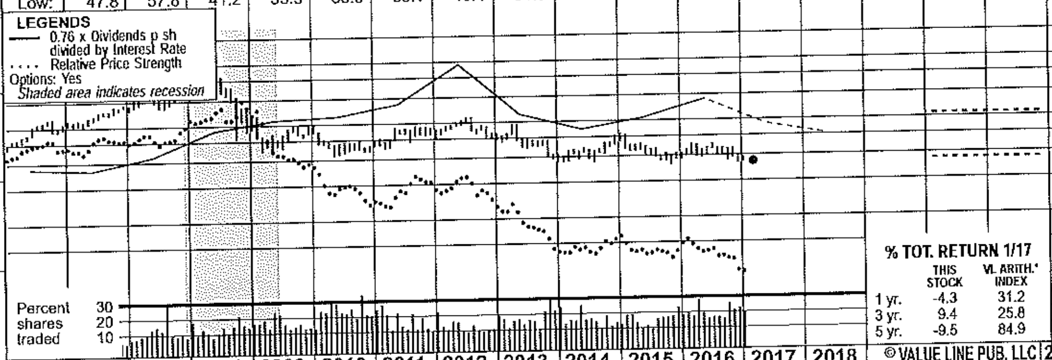
FIRSTENERGY NYSE-FE

RECENT PRICE 29.88 | P/E RATIO 16.2 (Trailing: 14.5; Median: 16.0) | RELATIVE P/E RATIO 0.84 | DIV'D YLD 4.8% | VALUE LINE

TIMELINESS 1 Raised 1/6/17
SAFETY 3 Lowered 2/22/13
TECHNICAL 4 Lowered 2/10/17
BETA .65 (1.00 = Market)

High:	61.7	75.0	84.0	53.6	47.8	46.5	51.1	46.8	40.8	41.7	36.6	31.4
Low:	47.8	57.8	41.2	35.3	33.6	36.1	40.4	31.3	30.0	28.9	29.3	29.5

Target Price Range 2020 | 2021 | 2022



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+65%)	17%
Low	30	(Nil)	5%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	2	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	2

Institutional Decisions

	1Q2016	2Q2016	3Q2016
to Buy	292	276	220
to Sell	193	213	229
Hld's(000)	322779	323739	314579

% TOT. RETURN 1/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-4.3	31.2
3 yr.	9.4	25.8
5 yr.	-9.5	84.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
26.88	40.83	37.31	37.76	36.35	36.03	42.00	44.70	41.70	43.76	38.87	36.57	35.60	35.74	35.48	33.30	33.30	33.10	Revenues per sh	34.50
5.48	6.45	4.79	7.60	7.55	7.22	8.34	9.04	8.80	8.50	5.75	6.05	6.30	4.55	6.33	6.10	6.90	6.95	"Cash Flow" per sh	7.50
2.84	2.54	1.47	2.77	2.84	3.82	4.22	4.38	3.32	3.25	1.88	2.13	2.97	.85	2.00	1.75	2.50	2.55	Earnings per sh A	2.75
1.50	1.50	1.50	1.91	1.71	1.85	2.05	2.20	2.20	2.20	2.20	2.20	1.65	1.44	1.44	1.44	1.44	1.44	Div'd Decl'd per sh B ■	1.60
2.86	3.35	2.60	2.57	3.66	4.12	5.36	9.47	7.23	6.44	5.45	7.09	6.90	8.42	6.83	7.05	6.40	6.60	Cap'l Spending per sh	6.50
24.86	23.92	25.13	26.04	27.86	28.30	29.45	27.17	28.08	28.03	31.75	31.29	30.32	29.49	29.33	26.50	27.85	29.20	Book Value per sh C	33.00
297.64	297.64	329.84	329.84	329.84	319.21	304.84	304.84	304.84	304.84	418.22	418.22	418.63	421.10	423.56	440.00	458.00	476.00	Common Shs Outst'g D	500.00
10.9	13.0	22.5	14.1	16.1	14.2	15.6	15.6	13.0	11.7	22.4	21.1	13.1	39.8	17.0	19.1	*Bold figures are*		Avg Ann'l P/E Ratio	14.5
.56	.71	1.28	.74	.86	.77	.83	.94	.87	.74	1.41	1.34	.74	2.10	.86	1.00	*Value Line*		Relative P/E Ratio	.90
4.8%	4.6%	4.5%	4.9%	3.7%	3.4%	3.1%	3.2%	5.1%	5.8%	5.2%	4.9%	4.3%	4.3%	4.2%	4.3%	*estimates*		Avg Ann'l Div'd Yield	4.0%
						12802	13627	12712	13339	16258	15294	14903	15049	15029	14650	15250	15750	Revenues ($mill)	17250
						1309.0	1342.0	1015.0	991.0	752.0	891.0	1245.0	356.0	844.0	765	1130	1210	Net Profit ($mill)	1430
						40.3%	36.7%	19.6%	38.6%	41.3%	41.1%	36.1%	5.6%	35.7%	38.5%	36.0%	36.0%	Income Tax Rate	36.0%
						2.4%	3.9%	12.8%	16.6%	9.3%	8.1%	6.0%	33.1%	13.9%	13.0%	9.0%	9.0%	AFUDC % to Net Profit	9.0%
						49.7%	52.4%	58.2%	59.5%	54.2%	53.7%	55.5%	60.7%	60.7%	63.0%	61.5%	60.0%	Long-Term Debt Ratio	58.0%
						50.3%	47.7%	41.8%	40.5%	45.8%	46.3%	44.5%	39.3%	39.3%	37.0%	38.5%	40.0%	Common Equity Ratio	42.0%
						17846	17383	20467	21124	28996	28263	28523	31596	31613	31350	33000	34725	Total Capital ($mill)	39400
						15383	17723	19164	19788	30337	32903	33252	35783	37214	38050	39000	40125	Net Plant ($mill)	43200
						9.0%	9.7%	6.9%	6.3%	4.0%	4.9%	6.0%	2.7%	4.3%	4.0%	5.0%	5.0%	Return on Total Cap'l	5.0%
						14.6%	16.2%	11.9%	11.6%	5.7%	6.8%	9.8%	2.9%	6.8%	6.5%	9.0%	8.5%	Return on Shr. Equity	8.5%
						14.6%	16.2%	11.9%	11.6%	5.7%	6.8%	9.8%	2.9%	6.8%	6.5%	9.0%	8.5%	Return on Com Equity E	8.5%
						7.7%	8.1%	4.0%	3.8%	NMF	NMF	2.6%	NMF	1.9%	1.0%	4.0%	4.0%	Retained to Com Eq	4.0%
						47%	50%	66%	68%	117%	103%	74%	NMF	72%	81%	57%	56%	All Div'ds to Net Prof	56%

CAPITAL STRUCTURE as of 9/30/16
Total Debt $22723 mill. **Due in 5 Yrs** $11148 mill.
LT Debt $18532 mill. **LT Interest** $890 mill.
Incl. $100 mill. capitalized leases.
(LT interest earned: 2.1x)

Leases, Uncapitalized Annual rentals $197 mill.
Pension Assets-12/15 $5338 mill. **Oblig** $9079 mill.

Pfd Stock None

Common Stock 425,743,282 shs.

MARKET CAP: $13 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	+.9	+1.1	-.8
Avg. Indust. Use (MWH)	NMF	NMF	NMF
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.2	+.3	+.3
Fixed Charge Cov. (%)	294	118	206

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '20-'22
Revenues	-.5%	-4.0%	-.5%
"Cash Flow"	-1.5%	-8.0%	4.0%
Earnings	-2.0%	-12.0%	5.0%
Dividends	-1.0%	-7.5%	1.0%
Book Value	1.0%	1.5%	1.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	4182	3496	3888	3483	15049
2015	3897	3468	4123	3541	15029
2016	3869	3401	3917	3463	14650
2017	4100	3550	4050	3550	15250
2018	4250	3650	4200	3650	15750

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.34	.27	.79	d.56	.85
2015	.53	.46	.95	.06	2.00
2016	.77	.34	.89	d.25	1.75
2017	.80	.50	.80	.40	2.50
2018	.85	.45	.85	.40	2.55

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.55	.55	.55	.55	2.20
2014	.36	.36	.36	.36	1.44
2015	.36	.36	.36	.36	1.44
2016	.36	.36	.36	.36	1.44
2017					

BUSINESS: FirstEnergy Corp. is a holding company for Ohio Edison, Pennsylvania Power, Cleveland Electric, Toledo Edison, Metropolitan Edison, Penelec, Jersey Central Power & Light, West Penn Power, Potomac Edison, & Mon Power. Provides electric service to over 6 million customers in OH, PA, NJ, WV, MD, & NY. Acq'd Allegheny Energy 2/11. Electric revenue breakdown by customer class not available. Generating sources: coal, 44%; nuclear, 26%; purchased, 30%. Fuel costs: 43% of revenues. '13 reported deprec. rate: 2.6%. Has 15,800 employees. Chairman: George M. Smart. President & CEO: Charles E. Jones. Incorporated: Ohio. Address: 76 South Main Street, Akron, Ohio 44308-1890. Telephone: 800-736-3402. Internet: www.firstenergycorp.com.

FirstEnergy has reached an agreement to sell some nonregulated generating assets. This is in line with the company's goal to move away from competitive businesses in favor of regulated utility operations. In November of 2016, management stated that the company wants to be fully regulated within a span of 12 to 18 months. FirstEnergy intends to sell 1,572 megawatts of gas-fired and hydro capacity for $925 million in cash. The deal requires approval of the Federal Energy Regulatory Commission and is expected to close in the third quarter. FirstEnergy will book a pretax charge of $266 million for the fourth quarter of 2016, which we will treat as nonrecurring. The company is still seeking regulatory and legislative changes in Ohio that would effectively make its generating assets there similar to regulated assets.

Unfavorable conditions for the nonregulated businesses have hurt FirstEnergy in recent years. Note the decline in profits, and the 2014 dividend reduction. The market is still concerned about FirstEnergy's presence in the nonregulated arena. In fact, the stock was the worst-performing issue in this industry last year, with a total return of just 1.9%.

Rate settlements were approved in Pennsylvania and New Jersey. In late January, FirstEnergy's utilities in Pennsylvania received increases totaling $291 million. This was a "black box" agreement in which an allowed return on equity was not specified. Jersey Central Power & Light received an $80 million hike at the start of 2017, based on a 9.6% return on a 45% common-equity ratio.

FirstEnergy might well report a loss for the fourth quarter of 2016. Each year in the final period, the company records a mark-to-market accounting item for pension and nonpension benefits accounting assumptions. FirstEnergy estimates that this will be $0.45-$0.75 a share. We assume no such charges in our 2017 and 2018 earnings estimates.

This timely stock has one of the highest yields of any electric utility. This reflects the uncertainties surrounding the nonregulated operations, as well as a lack of visibility about the next dividend hike. The 3- to 5-year total return potential is decent but poorly defined.

Paul E. Debbas, CFA *February 17, 2017*

(A) Dil. EPS. Excl. nonrec. gain (losses): '05, (28¢); '10, (68¢); '11, 33¢; '12, (29¢); '13, ($2.07); '14, (17¢); '15, (63¢); '16, ($2.90); gain from disc. ops.: '14, 20¢. '14 EPS don't sum due to rounding. Next egs. report due late Feb.
(B) Div'ds paid early Mar., June, Sep. & Dec. 5 div'ds decl. in '04, 3 in '13. ■ Div'd reinv. avail.
(C) Incl. intang.: In '15: $18.34/sh. (D) In mill.
(E) Rate base: Depr. orig. cost. Rates all'd on com. eq.: 9.75%-11.9%; earned on avg. com. eq., '15: 6.7%. Regulatory Climate: OH Above Avg.; PA, NJ Avg.; MD, WV Below Avg.

Company's Financial Strength	B+
Stock's Price Stability	85
Price Growth Persistence	10
Earnings Predictability	45

GREAT PLAINS EN'GY NYSE-GXP

RECENT PRICE 28.88 | P/E RATIO 18.3 (Trailing: 17.8 / Median: 16.0) | RELATIVE P/E RATIO 0.94 | DIV'D YLD 3.9% | VALUE LINE

High:	32.8	33.4	29.3	20.5	19.9	22.1	22.8	24.9	29.5	30.3	32.7	29.5
Low:	27.1	26.9	15.6	10.2	16.6	16.3	19.5	20.4	23.8	24.1	25.8	26.7

Target Price Range 2020 | 2021 | 2022

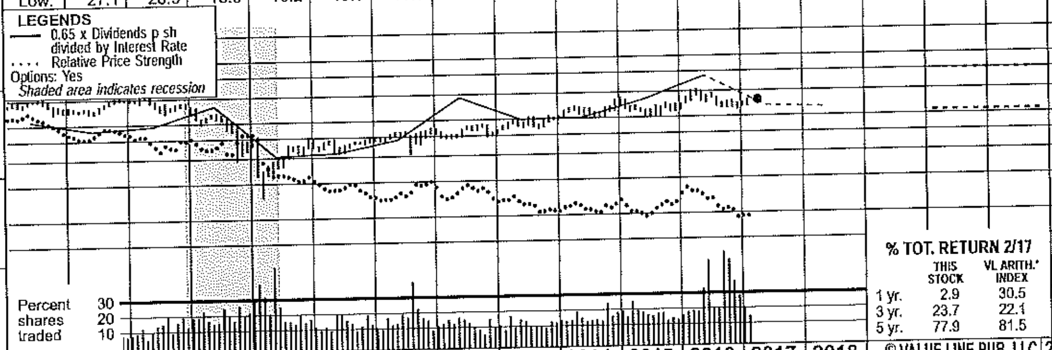
TIMELINESS 2 Lowered 1/27/17

SAFETY 3 Lowered 12/26/08

TECHNICAL 5 Lowered 3/3/17

BETA .75 (1.00 = Market)

LEGENDS
— 0.65 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+40%)	12%
Low	25	(-15%)	1%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	2	0	0	2	0	0	2	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2016	3Q2016	4Q2016
to Buy	189	204	217
to Sell	119	132	144
Hld's(000)	125742	193395	192383

Percent shares traded 30 20 10

% TOT. RETURN 2/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	2.9	30.5
3 yr.	23.7	22.1
5 yr.	77.9	81.5

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
23.61	26.91	31.04	33.13	34.85	33.30	37.89	14.00	14.51	16.62	17.03	15.05	15.90	16.66	16.21	12.43	12.95	13.40	Revenues per sh	14.75
4.70	4.40	4.69	4.75	4.54	3.86	4.24	3.09	3.27	4.12	3.51	3.45	4.01	4.01	3.98	3.35	3.50	3.85	"Cash Flow" per sh	4.50
1.59	2.04	2.27	2.46	2.18	1.62	1.86	1.16	1.03	1.53	1.25	1.35	1.62	1.57	1.37	1.61	1.30	1.45	Earnings per sh A	1.65
1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	.83	.83	.84	.86	.88	.94	1.00	1.06	1.12	1.18	Div'd Decl'd per sh B ■	1.35
4.38	1.91	2.19	2.66	4.49	6.05	6.15	8.86	6.49	4.76	3.40	4.01	4.42	5.10	4.42	2.86	2.75	2.60	Cap'l Spending per sh	2.50
12.59	13.58	13.82	15.35	16.37	16.70	18.18	21.39	20.62	21.26	21.74	21.75	22.58	23.26	23.68	24.73	24.85	25.10	Book Value per sh C	25.75
61.91	69.20	69.26	74.37	74.74	80.35	86.23	119.26	135.42	135.71	136.14	153.53	153.87	154.16	154.40	215.35	216.00	216.50	Common Shs Outst'g D	218.00
15.9	11.1	12.2	12.6	14.0	18.3	16.3	20.5	16.0	12.1	16.1	15.5	14.2	16.5	19.4	18.0	Bold figures are		Avg Ann'l P/E Ratio	19.0
.81	.61	.70	.67	.75	.99	.87	1.23	1.07	.77	1.01	.99	.80	.87	.98	.95	Value Line		Relative P/E Ratio	1.20
6.6%	7.3%	6.0%	5.4%	5.5%	5.6%	5.5%	7.0%	5.0%	4.5%	4.1%	4.1%	3.8%	3.6%	3.8%	3.6%	estimates		Avg Ann'l Div'd Yield	4.3%

CAPITAL STRUCTURE as of 12/31/16
Total Debt $4254.5 mill. Due in 5 Yrs $2074.6 mill.
LT Debt $3365.2 mill. LT Interest $166.9 mill.
(LT interest earned: 3.8x)

Leases, Uncapitalized Annual rentals $12.9 mill.

Pension Assets-12/16 $776.8 mill.
Oblig $1244.6 mill.

Pfd Stock None

Common Stock 215,384,601 shs.
as of 2/21/17
MARKET CAP: $6.2 billion (Large Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
3267.1	1670.1	1965.0	2255.5	2318.0	2309.9	2446.3	2568.2	2502.2	2676.0	2800	2900	Revenues ($mill)	3200
159.2	119.5	135.6	211.7	174.4	199.9	250.2	242.8	213.0	290.0	280	315	Net Profit ($mill)	355
30.7%	34.5%	25.0%	31.7%	32.7%	34.3%	34.0%	32.3%	36.7%	37.4%	37.0%	37.0%	Income Tax Rate	37.0%
10.6%	46.8%	57.0%	25.7%	3.9%	3.3%	10.4%	12.8%	4.5%	4.6%	3.0%	2.0%	AFUDC % to Net Profit	2.0%
40.7%	49.7%	53.2%	50.2%	47.8%	44.9%	50.0%	49.0%	50.3%	35.3%	39.0%	38.5%	Long-Term Debt Ratio	40.5%
57.9%	49.6%	46.2%	49.2%	51.6%	54.4%	49.4%	50.4%	49.1%	55.9%	61.0%	61.5%	Common Equity Ratio	59.5%
2709.8	5146.2	6044.5	5867.6	5741.2	6135.8	7029.1	7113.1	7440.6	9527.2	8785	8825	Total Capital ($mill)	9450
3444.5	6081.3	6651.1	6892.3	7053.5	7402.1	7746.4	8279.6	8662.4	8956.7	9075	9125	Net Plant ($mill)	8900
7.5%	3.5%	3.9%	5.3%	5.0%	5.0%	5.0%	4.7%	4.2%	3.9%	4.0%	4.5%	Return on Total Cap'l	5.0%
9.9%	4.6%	4.8%	7.2%	5.8%	5.9%	7.1%	6.7%	5.8%	4.7%	5.0%	6.0%	Return on Shr. Equity	6.5%
10.1%	4.6%	4.8%	7.3%	5.8%	5.9%	7.2%	6.7%	5.8%	5.1%	5.0%	6.0%	Return on Com Equity E	6.5%
.9%	NMF	.9%	3.4%	2.0%	2.2%	3.2%	2.7%	1.6%	1.8%	.5%	1.0%	Retained to Com Eq	1.0%
91%	NMF	81%	54%	66%	63%	55%	60%	73%	67%	86%	81%	All Div'ds to Net Prof	82%

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+.4	-1.9	+.7
Avg. Indust. Use (MWH)	1455	1450	1500
Avg. Indust. Revs. per KWH (¢)	6.79	6.96	7.29
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+.9	+.9	+1.1
Fixed Charge Cov. (%)	261	254	307

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	-7.5%	-1.0%	-.5%
"Cash Flow"	-1.5%	1.0%	3.0%
Earnings	-3.0%	3.5%	1.5%
Dividends	-5.0%	3.5%	5.0%
Book Value	4.0%	2.5%	1.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	585.1	648.4	782.5	552.2	2568.2
2015	549.1	609.0	781.4	562.7	2502.2
2016	572.1	670.8	856.8	576.3	2676.0
2017	625	675	875	625	2800
2018	650	700	900	650	2900

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.15	.34	.95	.12	1.57
2015	.12	.28	.82	.15	1.37
2016	.17	.20	.86	.39	1.61
2017	.11	.28	.80	.11	1.30
2018	.14	.32	.85	.14	1.45

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.217	.217	.217	.23	.88
2014	.23	.23	.23	.245	.94
2015	.245	.245	.245	.263	1.00
2016	.263	.263	.263	.275	1.06
2017	.275				

BUSINESS: Great Plains Energy Incorporated is a holding company for Kansas City Power & Light and two other subsidiaries, which supply electricity to 856,000 customers in western Missouri (71% of revenues) and eastern Kansas (29%). Acquired Aquila 7/08. Sold Strategic Energy (energy-marketing subsidiary) in '08. Electric revenue breakdown: residential, 40%; commercial, 39%; industrial, 9%; other, 12%. Generating sources: coal, 63%; nuclear, 13%; wind, 1%; gas & oil, 1%; purchased, 22%. Fuel costs: 22% of revenues. '16 reported deprec. rate (utility): 3.0%. Has 2,900 employees. Chairman, President & CEO: Terry Bassham. Inc.: Missouri. Address: 1200 Main St., Kansas City, Missouri 64105. Tel.: 816-556-2200. Internet: www.greatplainsenergy.com.

The proposed acquisition of Westar Energy by Great Plains Energy is facing some challenges. Great Plains would pay $8.6 billion (85% in cash, 15% in stock) for Westar, which is the parent company of utilities that serve more than 700,000 customers in Kansas. The transaction requires the approval of the regulatory commissions in Kansas and Missouri, plus that of the Federal Energy Regulatory Commission (FERC). However, although the deal has received some support in Kansas, it faces opposition from the commission's staff. A ruling is due by April 24th. The companies had hoped to avoid filing in Missouri, but the commission there ruled that an application is required. As for FERC, it can't vote on any matter as long as it lacks a quorum. Great Plains and Westar still hope to complete their combination in the second quarter of 2017.

Kansas City Power & Light is awaiting an order on its general rate case in Missouri. The utility is seeking an increase of $90.1 million (10.8%), based on a 9.9% return on a 49.88% common-equity ratio. The commission's decision is expected in late May, with new tariffs taking effect at the end of the month.

Our earnings estimates are based on Great Plains as a stand-alone entity. The company is already incurring operating and financing costs (including dilution from a stock offering last year) associated with the Westar takeover. This hurt share net by $0.24 in 2016. In addition, the company is booking mark-to-market accounting gains or losses stemming from an interest-rate swap. We assume no mark-to-market items in our 2017 estimate because these are impossible to predict, but will include them in our presentation once they are recorded. Note that we assume no merger-related expenses in our 2018 forecast, based on the assumption that if Great Plains is still operating in its current configuration, the proposed acquisition will have fallen through.

This timely stock offers a dividend yield that is slightly above the utility mean. Great Plains expects annual dividend growth of 5%-7% through the end of the decade regardless of whether the deal goes through, but the addition of Westar would likely enhance earnings growth.

Paul E. Debbas, CFA — *March 17, 2017*

(A) Diluted earnings. Excl. nonrec. gains (losses): '01, ($2.01); '02, (5¢); '03, 29¢; '04, (7¢); '09, 12¢; gain (losses) on disc. ops.: '03, (13¢); '04, 10¢; '05, (3¢); '08, 35¢. '14 & '16 EPS don't sum due to rounding. Next egs. report due early May. (B) Div'ds historically paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '16: $5.65/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in MO in '15: 9.5%; in KS in '15: 9.3%; earned on avg. com. eq., '16: 6.7%. Regulatory Climate: MO, Below Avg.; KS, Avg.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	20
Earnings Predictability	70

HAWAIIAN ELECTRIC NYSE-HE

RECENT PRICE 33.60 | P/E RATIO 14.7 (Trailing: 14.8; Median: 19.0) | RELATIVE P/E RATIO 0.74 | DIV'D YLD 3.7% | VALUE LINE

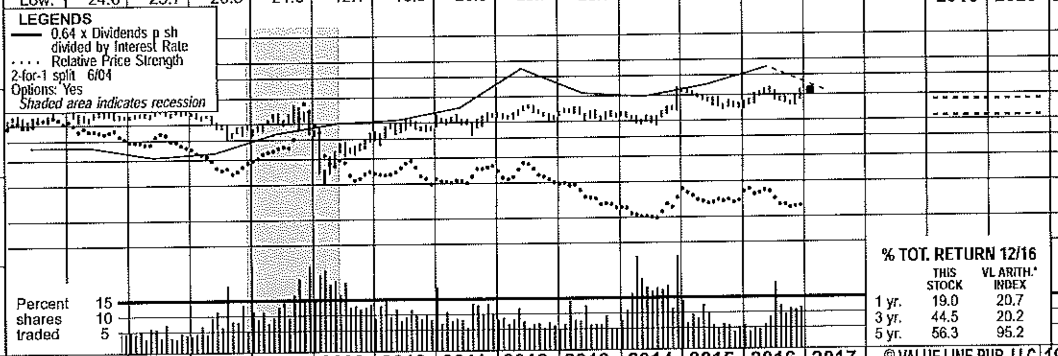
TIMELINESS	2	Lowered 11/4/16
SAFETY	2	Raised 11/2/12
TECHNICAL	3	Raised 1/20/17

BETA .70 (1.00 = Market)

High:	29.8	28.9	27.5	29.8	22.7	25.0	26.8	29.2	28.3	35.0	34.9	35.0
Low:	24.6	25.7	20.3	21.0	12.1	18.6	20.6	23.7	23.8	22.7	27.0	27.3

Target Price Range 2019 | 2020 | 2021

LEGENDS
— 0.64 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 6/04
Options: Yes
Shaded area indicates recession



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(-10%)	1%
Low	25	(-25%)	-3%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	8	0
to Sell	0	0	0	0	0	0	1	0	0

Institutional Decisions

	1Q2016	2Q2016	3Q2016
to Buy	106	117	129
to Sell	82	76	92
Hld's(000)	47029	47592	47770

Percent shares traded 15 10 5

% TOT. RETURN 12/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	19.0	20.7
3 yr.	44.5	20.2
5 yr.	56.3	95.2

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
26.05	24.26	22.46	23.49	23.85	27.36	30.21	30.40	35.56	24.96	28.14	33.76	34.46	31.98	31.59	24.22	21.40	22.00	Revenues per sh	24.00
3.08	3.33	3.52	3.54	3.09	3.22	3.19	3.01	2.72	2.59	2.88	3.18	3.28	3.22	3.41	3.31	4.20	3.70	"Cash Flow" per sh	4.00
1.27	1.60	1.62	1.58	1.36	1.46	1.33	1.11	1.07	.91	1.21	1.44	1.67	1.62	1.64	1.50	2.30	1.65	Earnings per sh A	2.00
1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	Div'd Decl'd per sh B ■	1.30
2.04	1.77	1.74	2.15	2.66	2.76	2.58	2.62	3.12	3.29	1.92	2.45	3.32	3.49	3.31	3.39	3.20	7.35	Cap'l Spending per sh	5.75
12.72	13.06	14.21	14.36	15.01	15.02	13.44	15.29	15.35	15.58	15.67	15.95	16.28	17.06	17.47	17.94	19.10	19.45	Book Value per sh C	21.50
65.98	71.20	73.62	75.84	80.69	80.98	81.46	83.43	90.52	92.52	94.69	96.04	97.93	101.26	102.57	107.46	108.75	109.00	Common Shs Outst'g D	112.00
12.9	11.8	13.5	13.8	19.2	18.3	20.3	21.6	23.2	19.8	18.6	17.1	15.8	16.2	15.9	20.4	13.5		Avg Ann'l P/E Ratio	14.0
.84	.60	.74	.79	1.01	.97	1.10	1.15	1.40	1.32	1.18	1.07	1.01	.91	.84	1.03	.70		Relative P/E Ratio	.90
7.5%	6.6%	5.7%	5.7%	4.8%	4.6%	4.6%	5.2%	5.0%	6.9%	5.5%	5.0%	4.7%	4.7%	4.8%	4.1%	4.0%		Avg Ann'l Div'd Yield	4.7%
						2460.9	2536.4	3218.9	2309.6	2665.0	3242.3	3375.0	3238.5	3239.5	2603.0	2325	2400	Revenues ($mill)	2700
						109.9	93.6	92.2	84.9	115.4	140.1	164.9	163.4	170.2	161.8	250	185	Net Profit ($mill)	215
						36.5%	35.4%	34.7%	34.1%	37.0%	35.1%	35.9%	34.0%	35.0%	36.5%	32.0%	36.5%	Income Tax Rate	36.5%
						8.4%	8.3%	14.2%	20.6%	7.4%	6.0%	6.9%	4.8%	5.5%	5.8%	4.0%	11.0%	AFUDC % to Net Profit	9.0%
						49.9%	47.6%	46.0%	48.0%	44.5%	44.9%	45.7%	44.0%	45.2%	43.5%	43.5%	45.5%	Long-Term Debt Ratio	49.5%
						48.6%	51.0%	52.7%	50.7%	54.3%	53.9%	53.1%	55.0%	53.8%	55.5%	55.5%	53.5%	Common Equity Ratio	49.5%
						2252.7	2501.8	2635.2	2840.8	2732.9	2841.3	3001.0	3142.9	3332.3	3473.5	3745	3970	Total Capital ($mill)	4850
						2647.5	2743.4	2907.4	3088.6	3165.9	3334.5	3594.8	3858.9	4148.8	4377.7	4520	5100	Net Plant ($mill)	6175
						6.4%	5.2%	4.7%	4.3%	5.6%	6.2%	6.7%	6.4%	6.2%	5.7%	7.5%	5.5%	Return on Total Cap'l	5.5%
						9.7%	7.1%	6.5%	5.8%	7.6%	8.9%	10.1%	9.3%	9.3%	8.2%	12.0%	8.5%	Return on Shr. Equity	8.5%
						9.9%	7.2%	6.5%	5.8%	7.7%	9.0%	10.2%	9.4%	9.4%	8.3%	12.0%	8.5%	Return on Com Equity E	9.0%
						.7%	.8%	.5%	NMF	1.4%	2.1%	4.2%	3.7%	2.3%	1.5%	5.5%	2.0%	Retained to Com Eq	3.0%
						93%	89%	93%	116%	82%	78%	59%	61%	75%	83%	55%	75%	All Div'ds to Net Prof F	69%

CAPITAL STRUCTURE as of 9/30/16
Total Debt $1579.1 mill. **Due in 5 Yrs** $441.5 mill.
LT Debt $1511.6 mill. **LT Interest** $70.3 mill.
Incl. $50 mill. 6.5% oblig. pfd. sec. of trust subsid.
(LT interest earned: 5.9x)
Leases, Uncapitalized Annual rentals $11.0 mill.
Pension Assets-12/15 $1271.5 mill.
Oblig. $1798.0 mill.
Pfd Stock $34.3 mill. **Pfd Div'd** $2.0 mill.
1,114,657 shs. 4¼% to 5¼%, $20 par. call. $20 to $21; 120,000 shs. 7⅝%, $100 par. call. $100.
Sinking fund ends 2018.
Common Stock 108,524,493 shs. as of 10/29/16
MARKET CAP: $3.6 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	-1.5	-1.0	-.2
Avg. Indust. Use (MWH)	6112	6118	5630
Avg. Indust. Revs. per KWH (¢)	29.31	29.82	22.71
Capacity at Yearend (Mw)	2354	2362	2224
Peak Load, Winter (Mw)	1535	1554	1610
Annual Load Factor (%)	71.0	69.3	66.9
% Change Customers (yr-end)	+.8	+.8	+.5
Fixed Charge Cov. (%)	398	410	399

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	1.5%	--	-3.0%
"Cash Flow"	--	4.0%	3.0%
Earnings	1.0%	8.5%	4.0%
Dividends	--	--	1.0%
Book Value	1.5%	2.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	784.1	796.7	831.2	826.5	3238.5
2014	783.7	798.7	867.1	790.0	3239.5
2015	637.9	623.9	717.2	624.0	2603.0
2016	551.0	566.2	646.1	561.7	2325
2017	575	575	675	575	2400

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.34	.41	.48	.39	1.62
2014	.45	.41	.46	.32	1.64
2015	.31	.33	.47	.39	1.50
2016	.30	.41	1.17	.42	2.30
2017	.30	.40	.55	.40	1.65

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.31	.31	.31	.31	1.24
2014	.31	.31	.31	.31	1.24
2015	.31	.31	.31	.31	1.24
2016	.31	.31	.31	.31	1.24
2017					

BUSINESS: Hawaiian Electric Industries, Inc. is the parent company of Hawaiian Electric Company, Inc. (HECO) & American Savings Bank (ASB). HECO & its subs., Maui Electric Co. (MECO) & Hawaii Electric Light Co. (HELCO), supply electricity to 458,000 customers on O'ahu, Maui, Molokai, Lanai, & Hawaii. Operating companies' systems are not interconnected. Disc. int'l power sub. in '01. Elec. rev. breakdown: res'l, 31%; comm'l, 34%; large light & power, 34%; other, 1%. Generating sources: oil, 54%; purchased, 46%. Fuel costs: 48% of revs. '15 reported depr. rate (util.): 3.2%. Has 3,900 empls. Chairman: Jeffrey N. Watanabe. Pres. & CEO: Constance H. Lau. Inc.: HI. Address: 1001 Bishop St., Suite 2900, Honolulu, HI 96808-0730. Tel.: 808-543-5662. Internet: www.hei.com.

Two of Hawaiian Electric Industries' utility subsidiaries have rate cases pending. Hawaiian Electric Company filed for a $106 million (6.9%) rate hike, based on a 10.6% return on a 57% common-equity ratio. The Public Utilities Commission (PUC) may grant interim rate relief within 10 to 11 months of the filing, which occurred in mid-December; there is no statutory time frame for a final order. Hawai'i Electric Light Company requested a $19.3 million (6.5%) tariff increase, based on a 10.6% return on a 57.1% common-equity ratio. HEI's other utility, Maui Electric, will put forth an application in the summer of 2017. The utilities, as a group, earned an ROE of just 8.1% for the 12-month period that ended on September 30th.

The regulatory climate in Hawaii is a cause for concern. Last year, the PUC rejected the proposed takeover of HEI by NextEra Energy amidst heavy opposition to the deal. Later, the PUC ruled that in 2017, capital expenditures and operating expenses under the state's rate mechanism will be accrued beginning on June 1st, not January 1st. This will likely reduce net profit by roughly $14 million, and is reflected in our 2017 earnings estimate.

Our 2016 earnings estimate requires an explanation. In the third quarter, HEI booked a $90 million (pretax) payment from NextEra due to the PUC's rejection of the proposed takeover. As a result, profits were about twice what they otherwise would have been, and most likely exceeded $2.00 a share for the full year.

The American Savings Bank subsidiary might benefit from tax reform. The utilities would have to pass through to customers any income tax reductions, but ASB would be able to retain them—a prospective benefit of $14 million, based on rates that have been discussed. And if interest expense is no longer deductible, HEI would be able to net this expense against ASB's interest income.

This stock is ranked favorably for Timeliness. That said, its dividend yield is not much higher than the utility mean, and the disbursement has not been raised since 1996. Moreover, the recent quotation is *above* our 2019-2021 Target Price Range.

Paul E. Debbas, CFA — *January 27, 2017*

(A) Dil. EPS. Excl. gains (losses) from disc. ops.: '00, (56¢); '01, (36¢); '03, (5¢); '04, 2¢; '05, (1¢); nonrec. gain (losses): '05, 11¢; '07, (9¢); '12, (25¢). Next earnings report due mid-Feb. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '15: $9.11/sh. (D) In mill., adj. for split. (E) Rate base: Orig. cost. Rate allowed on com. eq. in '11: HECO, 10%; in '12: HELCO, 10%; in '13: MECO, 9%; earn. on avg. com. eq., '15: 8.6%. Regulat. Climate: Below Avg. (F) Excl. div'ds paid through reinv. plan.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	30
Earnings Predictability	80

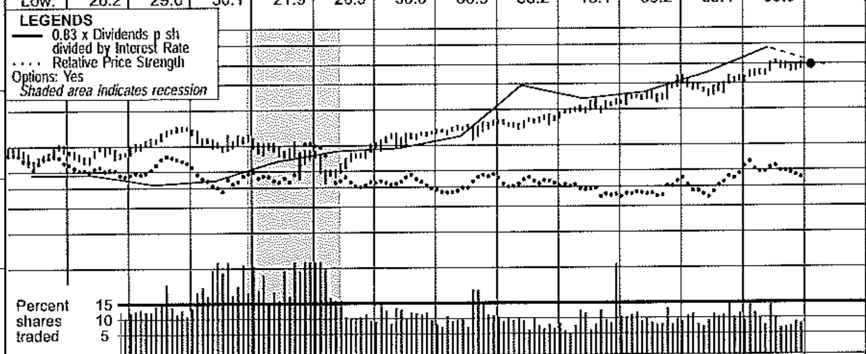
IDACORP, INC. NYSE-IDA

RECENT PRICE 79.28 | P/E RATIO 20.6 (Trailing: 20.3 / Median: 14.0) | RELATIVE P/E RATIO 1.04 | DIV'D YLD 2.8% | VALUE LINE

TIMELINESS 3 Lowered 8/5/16
SAFETY 2 Raised 8/2/13
TECHNICAL 3 Raised 1/13/17
BETA .75 (1.00 = Market)

High:	32.1	40.2	39.2	35.1	32.8	37.8	42.7	45.7	54.7	70.1	70.5	83.4	
Low:	26.2	29.0	30.1	21.9	20.9	30.0	33.9	38.2	43.1	50.2	55.4	65.0	

Target Price Range 2019 | 2020 | 2021



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(Nil)	4%
Low	55	(-30%)	-5%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	9	0	0	0	0	0	0	0	0
to Sell	2	1	2	2	1	3	0	0	0

Institutional Decisions

	1Q2016	2Q2016	3Q2016
to Buy	142	131	89
to Sell	83	93	120
Hld's(000)	38326	38314	37603

% TOT. RETURN 12/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	21.8	20.7
3 yr.	69.9	20.2
5 yr.	121.4	95.2

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
27.10	150.10	24.43	20.41	20.00	20.15	21.23	19.51	20.47	21.92	20.97	20.55	21.55	24.81	25.51	25.23	*24.80*	*25.25*	Revenues per sh	*26.75*
5.63	5.63	4.08	3.50	4.12	3.87	4.58	4.11	4.27	5.07	5.35	5.84	5.93	6.29	6.58	6.70	*6.85*	*7.15*	"Cash Flow" per sh	*8.00*
3.50	3.35	1.63	.96	1.90	1.75	2.35	1.86	2.18	2.64	2.95	3.36	3.37	3.64	3.85	3.87	*3.90*	*4.05*	Earnings per sh A	*4.50*
1.86	1.86	1.86	1.70	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.37	1.57	1.76	1.92	2.08	*2.24*	Div'd Decl'd per sh B ■ †	*2.70*
3.73	4.78	3.53	3.89	4.73	4.53	5.16	6.39	5.19	5.26	6.85	6.76	4.78	4.68	5.45	5.84	*5.95*	*5.65*	Cap'l Spending per sh	*6.25*
21.82	23.15	23.01	22.54	23.88	24.04	25.77	26.79	27.76	29.17	31.01	33.19	35.07	36.84	38.85	40.88	*42.65*	*44.45*	Book Value per sh C	*49.75*
37.61	37.63	38.02	38.34	42.22	42.66	43.63	45.06	46.92	47.90	49.41	49.95	50.16	50.23	50.27	50.34	*50.40*	*50.45*	Common Shs Outst'g D	*50.60*
10.9	11.4	18.9	26.5	15.5	16.7	15.1	18.2	13.9	10.2	11.8	11.5	12.4	13.4	14.7	16.2	*19.3*		Avg Ann'l P/E Ratio	*15.0*
.71	.58	1.03	1.51	.82	.89	.82	.97	.84	.68	.75	.72	.79	.75	.77	.82	*1.00*		Relative P/E Ratio	*.95*
4.9%	4.9%	6.0%	6.7%	4.1%	4.1%	3.4%	3.5%	4.0%	4.5%	3.4%	3.1%	3.3%	3.2%	3.1%	3.1%	2.8%		Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 9/30/16
Total Debt $1752.0 mill. Due in 5 Yrs $337.5 mill.
LT Debt $1745.5 mill. LT Interest $81.2 mill.
(LT interest earned: 3.4x)

Pension Assets-12/15 $559.6 mill. Oblig. $835.5 mill.

Pfd Stock None

Common Stock 50,401,768 shs. as of 10/21/16

MARKET CAP: $4.0 billion (Mid Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
926.3	879.4	960.4	1049.8	1036.0	1026.8	1080.7	1246.2	1282.5	1270.3	*1250*	*1275*	Revenues ($mill)	*1350*
100.1	82.3	98.4	124.4	142.5	166.9	168.9	182.4	193.5	194.7	*195*	*205*	Net Profit ($mill)	*225*
13.3%	14.3%	16.3%	15.2%	--	--	13.4%	28.3%	8.0%	19.0%	*25.0%*	*25.0%*	Income Tax Rate	*25.0%*
4.0%	9.7%	10.2%	10.5%	19.1%	23.3%	20.3%	12.3%	13.6%	16.3%	*16.0%*	*16.0%*	AFUDC % to Net Profit	*14.0%*
45.2%	48.9%	47.6%	50.2%	49.3%	45.6%	45.5%	46.6%	45.3%	45.6%	*46.0%*	*46.5%*	Long-Term Debt Ratio	*47.0%*
54.8%	51.1%	52.4%	49.8%	50.7%	54.4%	54.5%	53.4%	54.7%	54.4%	*54.0%*	*53.5%*	Common Equity Ratio	*53.0%*
2052.8	2364.2	2485.9	2807.1	3020.4	3045.2	3225.4	3465.9	3567.6	3783.3	*3995*	*4185*	Total Capital ($mill)	*4750*
2419.1	2616.6	2758.2	2917.0	3161.4	3406.6	3536.0	3665.0	3833.5	3992.4	*4145*	*4270*	Net Plant ($mill)	*4675*
6.2%	4.7%	5.3%	5.7%	6.0%	6.8%	6.5%	6.4%	6.6%	6.2%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
8.9%	6.8%	7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.9%	9.5%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.0%*
8.9%	6.8%	7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.9%	9.5%	*9.0%*	*9.0%*	Return on Com Equity E	*9.0%*
4.3%	2.4%	3.4%	4.8%	5.5%	6.5%	5.7%	5.6%	5.4%	4.8%	*4.5%*	*4.0%*	Retained to Com Eq	*3.5%*
51%	64%	55%	46%	41%	36%	41%	43%	46%	50%	*53%*	*55%*	All Div'ds to Net Prof	*60%*

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	+3.8	-3.6	+1.2
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.21	5.68	5.70
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	3407	3184	3402
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.5	+1.4	+1.8
Fixed Charge Cov. (%)	329	287	307

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	2.0%	3.5%	*1.0%*
"Cash Flow"	5.5%	6.0%	*3.5%*
Earnings	9.5%	8.0%	*3.0%*
Dividends	2.5%	8.0%	*7.5%*
Book Value	5.0%	6.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	264.9	304.0	381.1	296.2	1246.2
2014	292.7	317.8	382.2	289.8	1282.5
2015	279.4	336.3	369.2	285.4	1270.3
2016	281.0	315.4	372.0	*281.6*	*1250*
2017	*290*	*320*	*375*	*290*	*1275*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.70	.93	1.46	.55	3.64
2014	.55	.89	1.73	.69	3.85
2015	.47	1.31	1.46	.63	3.87
2016	.51	1.12	1.65	*.62*	*3.90*
2017	*.61*	*.97*	*1.90*	*.57*	*4.05*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.38	.38	.38	.43	1.57
2014	.43	.43	.43	.47	1.76
2015	.47	.47	.47	.51	1.92
2016	.51	.51	.51	.55	2.08
2017					

BUSINESS: IDACORP, Inc. is a holding company for Idaho Power Company, a regulated electric utility that serves 532,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon (population: 1 million). Most of the company's revenues are derived from the Idaho portion of its service area. Revenue breakdown: residential, 40%; commercial, 24%; industrial, 14%; irrigation, 13%; other, 9%. Generating sources: hydro, 36%; coal, 28%; gas, 13%; purchased, 23%. Fuel costs: 34% of revenues. '15 reported depreciation rate: 2.7%. Has 2,000 employees. Chairman: Robert A. Tinstman. President & CEO: Darrel T. Anderson. Incorporated: Idaho. Address: 1221 W. Idaho St., Boise, Idaho 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

We think IDACORP's earnings rose just slightly in the year that just ended. The year-to-year bottom-line comparison was tough because the company booked a $7.4 million tax benefit in the June quarter of 2015. Our share-profit estimate, which remains at $3.90, is within IDACORP's targeted range of $3.80-$3.95. The company plans to report fourth-quarter results in late February.

We estimate that earnings will advance 4% in 2017. Idaho Power, IDACORP's utility subsidiary, is experiencing healthy customer and kilowatt-hour sales growth. For the 12-month period that ended on September 30th, the customer growth rate was 1.8%, which is roughly twice the industry average. Volume growth, net of the effects of energy efficiency, was 1.4%, which is also well above the norm for electric companies. The key factors stimulating demand are population growth—Idaho is one of the fastest-growing states—and the service area's strong economy.

The utility is taking advantage of a regulatory mechanism that can help stabilize its earnings. Idaho Power may use up to $25 million of accumulated deferred investment tax credits annually to augment its income if the utility's return on equity falls below 9.5%. The company recorded $1.5 million of these credits in the first nine months of 2016, and expected to book another $500,000 in the fourth quarter. This regulatory mechanism is in place through 2019. It is possible that it will be extended beyond then.

IDACORP is in good financial condition. The company has no need for new common equity, and has no maturities of long-term debt until 2020. The fixed-charge coverage and common-equity ratio are very healthy. Putting it all together, IDACORP merits a Financial Strength rating of A.

IDACORP shares are expensively priced. The dividend yield is below 3%, which is low by utility standards. In fact, the recent quotation is just slightly below the upper end of our 2019-2021 Target Price Range. Consequently, total return potential over that time frame is negative, despite the company's good prospects for dividend growth.

Paul E. Debbas, CFA *January 27, 2017*

(A) Diluted EPS. Excl. nonrecurring gains (loss): '00, 22¢; '03, 26¢; '05, (24¢); '06, 17¢. '14 earnings don't add due to rounding. Next earnings report due late Feb. (B) Div'ds historically paid in late Feb., May, Aug., and Nov. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. intangibles. In '15: $26.16/sh. (D) In millions. (E) Rate base: Net original cost. Rate allowed on com. eq. in '11: 10% (imputed); earned on avg. com. eq., '15: 9.7%. Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	90
Earnings Predictability	90

INTEGRYS ENERGY NYSE-TEG

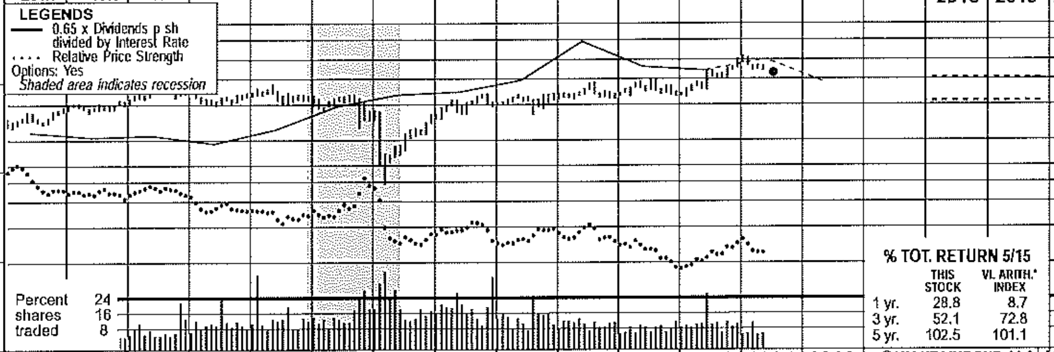
RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
68.88	24.2 (Trailing: 26.1 Median: 15.0)	1.27	3.9%

VALUE LINE

TIMELINESS – Suspended 7/4/14
SAFETY 2 Raised 6/24/11
TECHNICAL – Suspended 7/4/14
BETA .80 (1.00 = Market)

High:	50.5	60.0	57.8	60.6	53.9	45.1	54.4	54.6	61.9	63.6	80.9	83.7
Low:	43.5	47.7	47.4	48.1	36.9	19.4	40.5	42.8	50.8	52.6	52.1	68.0

Target Price Range 2018 | 2019 | 2020



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(-5%)	3%
Low	50	(-25%)	-3%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	5	5	11	12	0	12	1
to Sell	0	2	5	5	11	10	0	0	4

Institutional Decisions

	3Q2014	4Q2014	1Q2015
to Buy	138	146	141
to Sell	148	160	158
Hld's(000)	44422	44744	44850

% TOT. RETURN 5/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	28.8	8.7
3 yr.	52.1	72.8
5 yr.	102.5	101.1

Integrys Energy Group was created as a holding company on February 21, 2007 to oversee the entire operations of the recently merged WPS Resources and Peoples Energy. WPS acquired Peoples in an agreement under which each common share of Peoples was converted into .825 share of WPS common. The combination took the new name of Integrys Energy Group. All data on this page prior to 2/21/07 are for WPS Resources only.

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
173.37	160.01	135.44	184.86	98.71	67.27	60.44	54.07	70.92	52.11	*45.30*	*47.80*	Revenues per sh	*53.50*
7.40	6.33	5.19	4.69	5.34	6.70	6.13	6.95	7.72	6.46	*6.60*	*7.30*	"Cash Flow" per sh	*8.25*
4.09	3.51	2.48	1.58	2.28	3.24	2.88	3.67	4.33	2.77	*2.85*	*3.05*	Earnings per sh A	*4.00*
2.24	2.28	2.56	2.68	2.72	2.72	2.72	2.72	2.72	2.72	*2.72*	*2.72*	Div'd Decl'd per sh B ■	*2.80*
10.31	7.94	5.17	7.01	5.85	3.35	4.00	7.63	8.42	10.88	*12.05*	*12.00*	Cap'l Spending per sh	*13.50*
32.47	35.61	42.58	40.79	37.62	37.57	38.01	38.84	41.05	41.49	*41.65*	*42.05*	Book Value per sh C	*44.75*
40.16	43.06	75.99	75.99	75.98	77.35	77.91	77.90	79.45	79.53	*79.50*	*79.50*	Common Shs Outst'g D	*79.50*
13.4	14.7	21.4	30.7	14.8	14.7	17.5	14.8	13.3	23.1	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*14.0*
.71	.79	1.14	1.85	.99	.94	1.10	.94	.75	1.22	*estimates*		Relative P/E Ratio	*.90*
4.1%	4.4%	4.8%	5.5%	8.1%	5.7%	5.4%	5.0%	4.7%	4.2%			Avg Ann'l Div'd Yield	*5.0%*
6962.7	6890.7	10292	14048	7499.8	5203.2	4708.7	4212.4	5634.6	4144.2	*3600*	*3800*	Revenues ($mill)	*4250*
157.4	151.6	181.1	124.8	178.2	255.9	230.9	294.2	350.1	227.0	*230*	*250*	Net Profit ($mill)	*320*
22.9%	22.9%	32.2%	29.1%	41.5%	40.4%	36.7%	33.8%	37.6%	41.2%	*41.0%*	*41.0%*	Income Tax Rate	*41.0%*
1.0%	.5%	.7%	5.8%	4.5%	.7%	.4%	1.3%	4.3%	7.8%	*6.0%*	*6.0%*	AFUDC % to Net Profit	*5.0%*
39.0%	44.8%	40.8%	42.1%	45.1%	42.2%	38.3%	38.6%	47.2%	46.9%	*49.5%*	*50.0%*	Long-Term Debt Ratio	*49.5%*
58.7%	53.4%	58.3%	57.0%	53.9%	56.8%	60.6%	60.4%	52.0%	52.3%	*49.5%*	*49.5%*	Common Equity Ratio	*49.5%*
2222.4	2871.9	5552.0	5438.7	5304.4	5118.5	4884.5	5008.6	6268.6	6307.1	*6670*	*6775*	Total Capital ($mill)	*7150*
2049.4	2534.8	4463.8	4773.3	4945.1	5013.4	5199.1	5501.9	6410.5	6859.8	*7525*	*8140*	Net Plant ($mill)	*10275*
8.0%	6.4%	4.5%	3.5%	4.6%	6.2%	5.9%	6.9%	6.5%	4.8%	*4.5%*	*5.0%*	Return on Total Cap'l	*6.0%*
11.6%	9.6%	5.5%	4.0%	6.1%	8.7%	7.7%	9.6%	10.6%	6.8%	*7.0%*	*7.5%*	Return on Shr. Equity	*9.0%*
11.8%	9.7%	5.5%	3.9%	6.1%	8.7%	7.7%	9.6%	10.6%	6.8%	*7.0%*	*7.5%*	Return on Com Equity E	*9.0%*
5.3%	3.4%	.0%	NMF	NMF	2.3%	.7%	2.6%	4.4%	.2%	*.5%*	*1.0%*	Retained to Com Eq	*2.5%*
56%	65%	99%	NMF	118%	74%	91%	73%	59%	97%	*94%*	*88%*	All Div'ds to Net Prof	*70%*

CAPITAL STRUCTURE as of 3/31/15
Total Debt $3398.9 mill. **Due in 5 Yrs** $568.3 mill.
LT Debt $2956.3 mill. **LT Interest** $147.8 mill.
(LT interest earned: 3.3x)
Leases, Uncapitalized Annual rentals $4.7 mill.
Pension Assets-12/14 $1495.6 mill. **Oblig.** $1705.7 mill.
Pfd Stock $51.1 mill. **Pfd Div'd** $3.1 mill.
510,626 shs. 5.00% to 6.88%, callable $101 to $107.50; sinking fund begen 11/1/79. All cumulative, $100 par.
Common Stock 79,963,091 shs. as of 5/4/15
MARKET CAP: $5.5 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+.2	-.4	+6.0
Avg. C & I Use (KWH)	NA	NA	NA
Avg. C & I Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	3173	3344	NA
Peak Load, Summer (Mw)	2347	2400	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.4	+.4	-9.5
Fixed Charge Cov. (%)	367	410	254

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-6.0%	-16.0%	*NMF*
"Cash Flow"	1.0%	7.0%	*2.5%*
Earnings	1.0%	11.0%	*2.0%*
Dividends	2.5%	.5%	*.5%*
Book Value	4.0%	--	*1.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	1247.9	839.6	927.7	1197.2	4212.4
2013	1678.2	1116.0	1129.7	1710.7	5634.6
2014	1638.0	836.8	657.1	1012.3	4144.2
2015	1163.2	*800*	*636.8*	*1000*	*3600*
2016	*1250*	*825*	*675*	*1050*	*3800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	1.24	.65	.93	.86	3.67
2013	2.29	d.06	.47	1.63	4.33
2014	1.73	.10	.27	.66	2.77
2015	1.61	*.10*	*.29*	*.85*	*2.85*
2016	*1.70*	*.10*	*.35*	*.90*	*3.05*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.68	.68	.68	.68	2.72
2012	.68	.68	.68	.68	2.72
2013	.68	.68	.68	.68	2.72
2014	.68	.68	.68	.68	2.72
2015	.68	.68			

BUSINESS: Integrys Energy Group, Inc. is a holding company for Wisconsin Public Service, Peoples Gas, and four other utility subsidiaries. Has 450,000 electric customers in WI, 1.7 million gas customers in WI, IL, MN, and MI. Sold Upper Peninsula Power and retail electric and gas marketing operations in '14. Elec. rev. breakdown: residential, 29%; small commercial & industrial, 29%; large commercial & industrial, 19%; other, 23%. Generating sources: coal, 49%; gas, 12%; other, 5%; purchased, 34%. Fuel costs: 51% of revs. '14 depr. rates (utility): 2.2%-3.2%. Has 4,600 employees. Chairman & CEO: Charles A. Schrock. President & COO: Lawrence T. Borgard. Inc.: WI. Address: 130 East Randolph St., Chicago, IL 60601-6207. Tel.: 312-228-5400. Internet: www.integrysgroup.com.

Integrys Energy is awaiting two more regulatory approvals before the acquisition of the company by Wisconsin Energy can be completed. Integrys stockholders would receive $18.58 a share in cash and 1.128 shares of Wisconsin Energy stock for each of their shares, valuing the deal at $69.57 a share at Wisconsin Energy's recent price. The regulatory commissions in Minnesota and Illinois still need to rule on the combination. The due date for a decision in Illinois is July 6th, and the companies hope to get a written order in Minnesota by then. If all goes well, the transaction will close shortly thereafter. Accordingly, this might well be our last full-page report on Integrys. The stock's Timeliness rank is suspended due to the pending takeover.

We think shareholders should sell their stock on the open market. The stock price of Integrys is now just 1% below the value of the buyout, leaving little upside potential for shareholders. Integrys holders also have some downside risk that the deal will fall through, or that the price of Wisconsin Energy stock (like that of most utility equities) continues to weaken. Like many electric utility issues, Wisconsin Energy's stock price has fallen more than 10% so far this year. In fact, the value of the deal for Integrys holders has dropped below the $71.47-a-share value when the acquisition was announced nearly a year ago.

Peoples Gas in Illinois has received some criticism for its management of its accelerated main-replacement program. The cost of the project is much more than expected when it was proposed several years ago. A consultant made 95 recommendations, many of which the utility is already implementing. How this will affect the proposed takeover is unknown. The Illinois commission might welcome a new parent company for Peoples Gas.

Rate relief should help earnings advance this year and next. Tariffs of Peoples Gas and North Shore Gas (also in Illinois) were raised in early 2015. Wisconsin Public Service has filed for electric and gas rate hikes of $96.9 million and $9.1 million, respectively, based on a return of 10.2% on a common-equity ratio of 50.52%. New rates should take effect in early 2016.

Paul E. Debbas, CFA *June 19, 2015*

(A) Dil. EPS. Excl. nonrecur. gain (losses): '09, ($3.24); '10, (41¢); '14, 64¢; gains (losses) from disc. ops.: '07, $1.02; '08, 6¢; '09, 4¢; '11, (1¢); '12, (12¢); '13, 6¢; '14, 2¢. '12 & '14 EPS don't add due to rounding. Next egs. due early Aug. (B) Div'ds histor. paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '14: $27.27/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in WI in '15: 10.2%; in IL in '15: 9.05%; in MN in '14: 9.35%; earn. on avg. com. eq. '14: 6.8%. Regul. Climate: WI, Above Avg.; IL, Below Avg.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	55
Earnings Predictability	45

ITC HOLDINGS CORP. NYSE-ITC

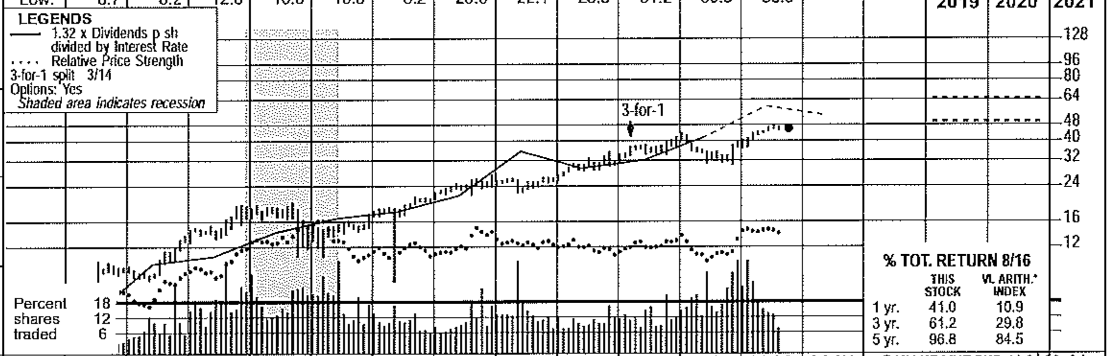
RECENT PRICE 46.22 | P/E RATIO 23.9 (Trailing: 30.0 / Median: 22.0) | RELATIVE P/E RATIO 1.26 | DIV'D YLD 1.9% | VALUE LINE

TIMELINESS	– Suspended 2/19/16
SAFETY	2 Raised 6/24/11
TECHNICAL	– Suspended 2/19/16

BETA .70 (1.00 = Market)

High:	10.1	13.7	19.5	20.0	17.6	21.3	27.3	26.6	35.6	42.0	44.0	47.5
Low:	8.7	8.2	12.6	10.8	10.8	8.2	20.6	22.1	25.5	31.2	30.3	36.5

Target Price Range 2019 | 2020 | 2021



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+40%)	11%
Low	50	(+10%)	5%

Insider Decisions

	N	D	J	F	M	A	M	J	J
to Buy	0	0	0	0	1	0	1	0	0
Options	0	0	8	0	0	8	6	1	8
to Sell	0	0	0	0	0	0	3	1	0

Institutional Decisions

	4Q2015	1Q2016	2Q2016
to Buy	203	145	129
to Sell	163	230	190
Hld's(000)	134973	129567	129827

% TOT. RETURN 8/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	41.0	10.9
3 yr.	61.2	29.8
5 yr.	96.8	84.5

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
--	--	--	--	1.37	2.06	1.76	3.31	4.15	4.13	4.58	4.92	5.30	5.98	6.59	6.84	*7.80*	*8.85*	Revenues per sh	*11.75*
--	--	--	--	.35	.68	.58	1.10	1.37	1.44	1.53	1.73	1.88	2.24	2.40	2.54	*2.95*	*3.35*	"Cash Flow" per sh	*4.50*
--	--	--	--	.03	.35	.31	.56	.73	.86	.95	1.10	1.20	1.47	1.54	1.56	*1.85*	*2.15*	Earnings per sh A	*2.75*
--	--	--	--	--	.18	.36	.38	.40	.42	.44	.46	.49	.54	.61	.70	*.81*	*.93*	Div'd Decl'd per sh B ■ †	*1.30*
--	--	--	--	.83	1.19	1.32	2.23	2.70	2.69	2.55	3.62	5.12	5.22	4.73	4.48	*6.50*	*6.70*	Cap'l Spending per sh	*6.75*
--	--	--	--	2.14	2.64	4.18	4.37	6.24	6.73	7.34	8.18	9.03	10.25	10.76	11.19	*12.25*	*13.55*	Book Value per sh C	*18.00*
--	--	--	--	92.04	99.69	127.19	128.75	148.96	150.25	152.15	153.97	156.75	157.50	155.14	152.70	*154.00*	*155.00*	Common Shs Outst'g D	*158.00*
--	--	--	--	--	26.3	33.0	27.6	23.2	17.1	20.0	21.4	20.7	20.4	23.8	22.8	*Bold figures are*		Avg Ann'l P/E Ratio	*20.5*
--	--	--	--	--	1.40	1.78	1.47	1.40	1.14	1.27	1.34	1.32	1.15	1.25	1.15	*Value Line*		Relative P/E Ratio	*1.30*
--	--	--	--	--	1.9%	3.5%	2.4%	2.3%	2.8%	2.3%	1.9%	2.0%	1.8%	1.7%	2.0%	*estimates*		Avg Ann'l Div'd Yield	*2.3%*

CAPITAL STRUCTURE as of 6/30/16
Total Debt $4598.1 mill. Due in 5 Yrs $1725.2 mill.
LT Debt $4146.9 mill. LT Interest $185.0 mill.
(LT interest earned: 2.6x)

Pension Assets-12/15 $58.1 mill. Oblig $97.2 mill.

Pfd Stock None

Common Stock 153,372,055 shs. as of 7/22/16

MARKET CAP: $7.1 billion (Large Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
223.6	426.2	617.9	621.0	696.8	757.4	830.5	941.3	1023.0	1044.8	*1200*	*1370*	Revenues ($mill)	*1875*
33.2	73.3	109.2	130.9	145.7	171.7	187.9	233.5	244.1	242.4	*290*	*335*	Net Profit ($mill)	*460*
29.2%	33.3%	38.1%	37.2%	36.1%	35.6%	36.6%	33.7%	38.1%	36.9%	*38.0%*	*38.0%*	Income Tax Rate	*38.0%*
15.0%	14.7%	13.8%	13.1%	11.9%	12.5%	16.0%	16.3%	10.6%	14.4%	*14.0%*	*12.0%*	AFUDC % to Net Profit	*9.0%*
70.3%	72.4%	70.8%	70.6%	69.1%	67.8%	63.8%	67.9%	70.2%	70.4%	*69.5%*	*67.0%*	Long-Term Debt Ratio	*64.5%*
29.7%	27.6%	29.2%	29.4%	30.9%	32.2%	36.2%	32.1%	29.8%	29.6%	*30.5%*	*33.0%*	Common Equity Ratio	*35.5%*
1794.5	2041.5	3177.3	3445.9	3614.3	3903.9	3910.2	5025.8	5598.1	5770.0	*6200*	*6395*	Total Capital ($mill)	*8050*
1197.9	1960.4	2304.4	2542.1	2872.3	3415.8	4134.6	4846.5	5496.9	6109.6	*6945*	*7805*	Net Plant ($mill)	*10175*
3.0%	5.7%	5.4%	5.7%	6.1%	6.3%	6.7%	6.2%	6.0%	5.9%	*6.0%*	*7.0%*	Return on Total Cap'l	*7.0%*
6.2%	13.0%	11.8%	12.9%	13.0%	13.6%	13.3%	14.5%	14.6%	14.2%	*15.5%*	*16.0%*	Return on Shr. Equity	*16.0%*
6.2%	13.0%	11.8%	12.9%	13.0%	13.6%	13.3%	14.5%	14.6%	14.2%	*15.5%*	*16.0%*	Return on Com Equity E	*16.0%*
NMF	4.5%	5.4%	6.8%	7.1%	8.0%	8.0%	9.3%	8.9%	7.8%	*9.0%*	*9.0%*	Retained to Com Eq	*9.0%*
115%	66%	54%	48%	45%	41%	40%	36%	39%	45%	*43%*	*43%*	All Div'ds to Net Prof	*45%*

CURRENT POSITION ($MILL.)	2014	2015	6/30/16
Cash Assets	27.7	13.8	6.1
Receivables	101.0	104.3	147.9
Inventory (FIFO)	30.9	25.8	27.8
Other	27.2	25.3	179.3
Current Assets	186.8	169.2	361.1
Accts Payable	108.0	124.3	146.9
Debt Due	175.0	395.3	451.2
Other	180.0	199.6	186.8
Current Liab.	463.0	719.2	785.0
Fix Chg. Cov.	309%	266%	262%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	14.0%	8.5%	*10.5%*
"Cash Flow"	16.5%	10.5%	*11.0%*
Earnings	23.0%	12.5%	*10.5%*
Dividends	21.5%	8.0%	*13.0%*
Book Value	16.0%	9.5%	*9.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	217.3	229.8	238.8	255.4	941.3
2014	258.6	263.2	270.1	231.1	1023.0
2015	272.5	275.1	273.2	224.0	1044.8
2016	280.1	298.0	*306.9*	*315*	*1200*
2017	*335*	*340*	*345*	*350*	*1370*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.32	.30	.37	.48	1.47
2014	.43	.34	.47	.30	1.54
2015	.43	.46	.42	.24	1.56
2016	.42	.46	*.48*	*.49*	*1.85*
2017	*.50*	*.55*	*.55*	*.55*	*2.15*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.1175	.1175	.126	.126	.49
2013	.126	.126	.1425	.1425	.54
2014	.1425	.1425	.1625	.1625	.61
2015	.1625	.1625	.1875	.1875	.70
2016	.1875	.1875	.2155		

BUSINESS: ITC Holdings Corp. engages in the transmission of electricity in the United States. The company operates primarily as a conduit, moving power from generators to local distribution systems either through its own system or in conjunction with neighboring transmission systems. Acquired Michigan Electric Transmission Company 10/06; Interstate Power & Light's transmission assets 12/07. Has assets in Michigan, Iowe, Minnesota, Illinois, Missouri, and Kansas. Operations are regulated by the Federal Energy Regulatory Commission (FERC). '15 reported depreciation rate: 2.1%. Has about 600 employees. Chairman, President & CEO: Joseph L. Welch. Inc.: Michigan. Address: 27175 Energy Way, Novi, Michigan 48377. Tel.: 248-946-3000. Internet: www.itctransco.com.

The acquisition of ITC Holdings is progressing. Fortis, a Canadian company with utilities in the U.S., would pay US$22.57 in cash plus .752 of a Fortis share for each ITC share. The Fortis shares trade on a Canadian exchange, so the value of the deal will fluctuate based not only on the price of Fortis stock, but on the exchange rate between the U.S. and Canadian dollars. The transaction is now valued at almost $47.00 a share. Each company's stockholders have approved the combination, as have the regulators in Oklahoma and Illinois. The Federal Energy Regulatory Commission (FERC) and the commissions in three other states must still rule on the deal. The companies expect it to be completed by yearend.

We advise ITC holders to sell their shares on the open market. The recent price is just 2% below the value of the buyout, so there isn't much upside potential for ITC holders. There is downside risk if the deal fails to win regulatory approval, however. The Timeliness rank of ITC stock is suspended due to the pending acquisition.

ITC is taking charges associated with the Fortis deal and for the possible refund of previously collected revenues. Merger-related costs reduced earnings by $0.14 a share in the first half of 2016. More significantly, over the past several quarters, the company has been taking reserves for the probable refund of previously collected revenues. This lowered profits by $0.11 a share in the first two quarters of 2016. Transmission users have filed two complaints with FERC against transmission owners in the Midwest, contending that allowed returns on equity are too high and should be reduced. An administrative law judge has recommended cuts in the allowed ROEs, but FERC has yet to rule on either complaint. Each percentage point reduction in ITC's allowed ROE would reduce the company's earning power by $30 million after taxes.

The board of directors has raised the dividend. The increase was $0.11 a share (14.9%) annually. However, unlike most utilities, ITC's dividend yield is still below the market median. Of course, ITC is not like other utilities, being the sole publicly traded transmission-only company.

Paul E. Debbas, CFA *September 16, 2016*

(A) Diluted earnings. '15 earnings don't add to full-year total due to rounding. Next earnings report due late Oct. (B) Dividends historically paid in early March, June, Sept., and Dec. ■ Dividend reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '15: $1.26 billion, $8.24/sh. (D) In millions, adjusted for stock split. (E) Rates allowed on common equity: 12.16%-13.88%. Earned on avg. com. eq., '15: 14.2%. Regulatory Climate: Above Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	90
Earnings Predictability	90

MGE ENERGY INC. NDQ-MGEE

RECENT PRICE 63.65 | P/E RATIO 28.5 (Trailing: 29.2 Median: 16.0) | RELATIVE P/E RATIO 1.46 | DIV'D YLD 2.0% | VALUE LINE

TIMELINESS 4 Lowered 3/10/17

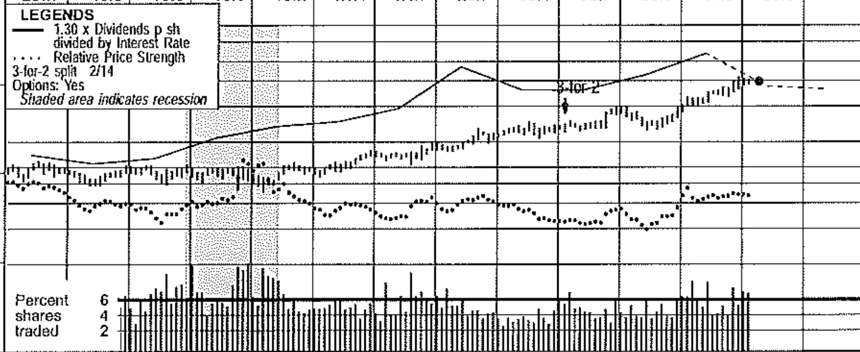
SAFETY 1 New 1/3/03

TECHNICAL 3 Lowered 3/3/17

BETA .70 (1.00 = Market)

High:	24.7	24.8	24.3	25.5	29.1	31.9	37.4	40.5	48.0	48.0	66.9	65.9
Low:	19.5	19.6	18.6	18.2	21.4	24.7	28.7	33.4	35.7	36.5	44.8	60.3

LEGENDS
— 1.30 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 2/14
Options: Yes
Shaded area indicates recession



Target Price Range
2020 | 2021 | 2022
120
100
80
64
48
32
24
20
16
12
8

2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(-15%)	-1%
Low	45	(-30%)	-6%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	1	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2016	3Q2016	4Q2016
to Buy	79	74	75
to Sell	51	57	64
Hld's(000)	12637	12692	13125

Percent shares traded 6 4 2

% TOT. RETURN 2/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	34.6	30.5
3 yr.	78.8	22.1
5 yr.	150.8	81.5

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
13.03	13.17	14.59	13.89	16.73	16.13	16.33	17.35	15.40	15.36	15.76	15.61	17.04	17.88	16.27	15.71	*16.45*	*17.45*	Revenues per sh	*20.85*
2.52	2.22	1.96	1.92	2.00	2.34	2.46	2.68	2.66	2.76	2.94	2.98	3.28	3.49	3.33	3.47	*3.55*	*4.00*	"Cash Flow" per sh	*5.15*
1.08	1.13	1.14	1.18	1.05	1.37	1.51	1.59	1.47	1.67	1.76	1.86	2.16	2.32	2.06	2.18	*2.30*	*2.45*	Earnings per sh A	*3.25*
.89	.89	.90	.91	.92	.93	.94	.96	.97	.99	1.01	1.04	1.07	1.11	1.16	1.21	*1.25*	*1.30*	Div'd Decl'd per sh B ▪	*1.45*
1.65	2.97	3.02	3.13	2.80	2.94	4.14	3.08	2.35	1.76	1.88	2.84	3.43	2.67	2.08	2.41	*2.55*	*2.80*	Cap'l Spending per sh	*3.45*
8.45	8.62	9.56	11.06	11.21	11.93	12.99	13.92	14.47	15.14	15.89	16.71	17.81	19.02	19.92	20.89	*20.85*	*22.15*	Book Value per sh E	*25.70*
25.61	26.36	27.52	30.59	30.68	31.46	32.93	34.36	34.67	34.67	34.67	34.67	34.67	34.67	34.67	34.67	*35.00*	*35.00*	Common Shs Outst'g C	*36.00*
14.8	16.0	17.5	18.0	22.4	15.9	15.0	14.2	15.1	15.0	15.8	17.2	17.0	17.2	20.3	24.9	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.76	.87	1.00	.95	1.19	.86	.80	.85	1.01	.95	.99	1.09	.96	.91	1.02	1.31	*Value Line*		Relative P/E Ratio	*.95*
5.5%	5.0%	4.5%	4.3%	3.9%	4.3%	4.1%	4.2%	4.4%	4.0%	3.6%	3.2%	2.9%	2.8%	2.8%	2.2%	*estimates*		Avg Ann'l Div'd Yield	*3.0%*

CAPITAL STRUCTURE as of 12/31/16
Total Debt $387.1 mill. Due in 5 Yrs $57.8 mill.
LT Debt $382.8 mill. LT Interest $20.0 mill.
(LT interest earned: 7.0x)

Leases, Uncapitalized Annual rentals $1.3 mill.
Pension Assets-12/16 $311.9 mill.
Obligation $349.6 mill.

Pfd Stock None

Common Stock 34,668,370 shs.
as of 2/1/17
MARKET CAP: $2.2 billion (Mid Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
537.6	596.0	533.8	532.6	546.4	541.3	590.9	619.9	564.0	544.7	*575*	*610*	Revenues ($mill)	*750*
48.8	52.8	51.0	57.7	60.9	64.4	74.9	80.3	71.3	75.6	*80.0*	*85.0*	Net Profit ($mill)	*115*
36.3%	35.5%	35.6%	36.9%	37.1%	37.7%	37.5%	37.5%	36.7%	36.0%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
--	--	--	--	--	--	--	--	2.2%	2.0%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
35.2%	36.3%	39.0%	38.9%	39.6%	38.2%	39.3%	37.5%	36.2%	34.6%	*36.0%*	*36.0%*	Long-Term Debt Ratio	*36.0%*
64.8%	63.7%	61.0%	61.1%	60.4%	61.8%	60.7%	62.5%	63.8%	65.4%	*64.0%*	*64.0%*	Common Equity Ratio	*64.0%*
660.1	750.6	822.7	859.4	911.9	937.9	1016.9	1054.7	1081.5	1106.9	*1145*	*1210*	Total Capital ($mill)	*1450*
844.0	901.2	939.8	968.0	995.6	1073.5	1160.2	1208.1	1243.4	1282.1	*1320*	*1360*	Net Plant ($mill)	*1500*
8.1%	7.7%	6.9%	7.6%	7.8%	7.9%	8.3%	8.5%	7.5%	7.7%	*8.0%*	*8.0%*	Return on Total Cap'l	*9.0%*
11.4%	11.0%	10.2%	11.0%	11.1%	11.1%	12.1%	12.2%	10.3%	10.4%	*11.0%*	*11.0%*	Return on Shr. Equity	*12.5%*
11.4%	11.0%	10.2%	11.0%	11.1%	11.1%	12.1%	12.2%	10.3%	10.4%	*11.0%*	*11.0%*	Return on Com Equity D	*12.5%*
4.3%	4.4%	3.4%	4.4%	4.7%	4.9%	6.1%	6.4%	4.5%	4.7%	*5.0%*	*5.0%*	Retained to Com Eq	*7.0%*
62%	60%	66%	60%	57%	56%	50%	48%	56%	55%	*55%*	*54%*	All Div'ds to Net Prof	*45%*

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	-0.5	-0.3	1.1
Avg. Indust. Use (MWH)	2463	2484	2329
Avg. Indust. Revs. per KWH (¢)	7.78	8.17	7.55
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	783	783	783
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	702	616	645

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	0.5%	1.5%	*4.0%*
"Cash Flow"	5.0%	4.5%	*7.0%*
Earnings	6.0%	6.0%	*7.0%*
Dividends	2.5%	3.0%	*3.0%*
Book Value	6.0%	5.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	210.3	128.8	135.1	145.7	619.9
2015	170.1	122.1	140.8	131.0	564.0
2016	147.5	121.6	136.7	138.9	544.7
2017	*155*	*130*	*145*	*145*	*575*
2018	*165*	*140*	*150*	*155*	*610*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.80	.41	.67	.44	2.32
2015	.53	.39	.82	.32	2.06
2016	.49	.47	.80	.42	2.18
2017	*.48*	*.48*	*.85*	*.49*	*2.30*
2018	*.52*	*.52*	*.88*	*.53*	*2.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B ▪ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.2634	.2634	.2717	.2717	1.07
2014	.2717	.2717	.2825	.2825	1.11
2015	.2825	.2825	.2950	.2950	1.16
2016	.2950	.2950	.3075	.3075	1.21
2017	.3075				

BUSINESS: MGE Energy Inc. is a holding company for Madison Gas and Electric, which provides electric service to approximately 149,000 customers in a 316-square-mile area of Dane County and gas service to 154,000 customers in 1,682 square miles in seven counties in Wisconsin. Electric revenue breakdown, '16: residential, 34%; commercial, 53%; industrial, 4%; public authorities and other, 9%. Generating sources, '16: coal, 48%; purchased power, 30%; natural gas and other, 22%. Fuel costs: 21% of revenues. '16 reported depreciation rate: 3.5%. Has 704 employees. Chairman: Gary J. Wolter. President & CEO: Jeffrey M. Keebler. Incorporated: Wisconsin. Address: 133 South Blair St., Madison, WI 53788. Telephone: 608-252-7000. Internet: www.mgeenergy.com.

Shares of MGE Energy have continued to advance in price over the past three months, and are presently trading near a high-water mark. The company reported solid results for the fourth quarter. Revenues and earnings per share rebounded nicely from the unimpressive figures that were generated in the prior-year period. Performance in the December quarter benefited from higher electric consumption due partly to an increase in residential customers. In addition, colder weather led to greater sales of natural gas. Temperature variations had also been kind to the utility last summer, as warmer weather resulted in an increase in electric consumption.

The utility subsidiary is proposing to construct, own, and operate its largest wind farm to date. The 66-megawatt wind farm would be located close to Saratoga, Iowa, roughly 200 miles west of Madison, Wisconsin. The site is well situated with persistent winds and proximity to transmission infrastructure. MGE is seeking approval for the project from the Public Service Commission of Wisconsin. Assuming this is granted, construction of the $107 million project could begin next year.

Prospects for the coming years appear solid. We expect steady bottom-line growth for MGE from 2017 onward. The company's utility operations ought to benefit from favorable demographics in its service territories. Growth in the residential customer base will probably remain an important driver of performance here. Efforts to control operating costs should support profitability.

These shares are unfavorably ranked for year-ahead relative price performance. MGE earns good marks for Safety, Financial Strength, Price Stability, and Earnings Predictability. Volatility is below average, too (Beta: 0.70). However, this issue presently lacks long-term total return potential. The stock's valuation appears fairly rich in relation to its historical average, following a strong run-up in the share price that began around mid-2015. On top of that, the dividend yield is subpar for a utility. All things considered, subscribers can probably find more-attractive choices elsewhere at this time.

Michael Napoli, CFA *March 17, 2017*

(A) Diluted earnings. Next earnings report due early May. (B) Dividends historically paid in mid-March, June, September, and December. ▪ Dvd. reinvestment plan available. (C) In millions, adjusted for split. (D) Rate allowed on common equity in '16: 10.2%; earned on common equity, '16: 10.4%. Regulatory Climate: Above Average. (E) Includes regulatory assets. In 2016: $164.9 mill., $4.76 per share.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	70
Earnings Predictability	90

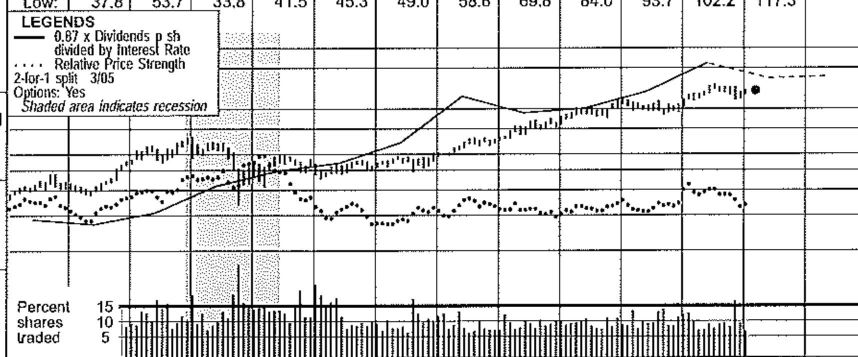
NEXTERA ENERGY NYSE-NEE

RECENT PRICE 123.86 | P/E RATIO 17.5 (Trailing: 21.4 / Median: 15.0) | RELATIVE P/E RATIO 0.90 | DIV'D YLD 3.2% | VALUE LINE

TIMELINESS 3 Lowered 9/23/16
SAFETY 2 Lowered 2/26/10
TECHNICAL 3 Lowered 12/30/16
BETA .65 (1.00 = Market)

High:	55.6	72.8	73.8	60.6	56.3	61.2	72.2	89.8	110.8	112.6	132.0	124.9
Low:	37.8	53.7	33.8	41.5	45.3	49.0	58.6	69.8	84.0	93.7	102.2	117.3

Target Price Range
2020 | 2021 | 2022



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	170	(+35%)	11%
Low	125	(Nil)	4%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	1	1
Options	0	2	1	1	1	0	0	1	0
to Sell	0	2	2	1	1	0	0	2	0

Institutional Decisions

	1Q2016	2Q2016	3Q2016
to Buy	514	496	434
to Sell	500	488	540
Hld's(000)	354339	345720	341286

% TOT. RETURN 1/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	14.1	31.2
3 yr.	47.2	25.8
5 yr.	142.6	84.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
24.10	22.74	26.13	28.27	30.00	38.75	37.47	40.13	37.82	36.39	36.88	33.62	34.80	38.42	37.93	33.50	34.25	35.70	Revenues per sh	39.75
5.02	4.51	5.36	5.60	6.18	6.77	6.85	8.03	8.75	9.62	9.29	8.69	10.54	12.10	12.92	12.60	13.55	14.35	"Cash Flow" per sh	16.50
2.31	2.01	2.45	2.46	2.32	3.23	3.27	4.07	3.97	4.74	4.82	4.56	4.83	5.60	6.06	5.78	6.55	6.95	Earnings per sh A	8.25
1.12	1.16	1.20	1.30	1.42	1.50	1.64	1.78	1.89	2.00	2.20	2.40	2.64	2.90	3.08	3.48	3.92	4.50	Div'd Decl'd per sh B ■ †	5.50
3.28	3.44	3.75	3.75	4.09	9.22	12.32	12.80	14.52	13.89	15.93	22.31	15.36	15.84	18.17	20.00	14.60	15.10	Cap'l Spending per sh	18.00
17.10	17.48	18.91	20.25	21.52	24.49	26.35	28.57	31.35	34.36	35.92	37.90	41.47	44.96	48.97	50.50	54.05	56.55	Book Value per sh C	67.00
351.71	365.51	368.53	372.24	394.85	405.40	407.35	408.92	413.62	420.86	416.00	424.00	435.00	443.00	461.00	482.00	496.00	496.00	Common Shs Outst'g D	502.00
12.5	14.2	12.6	13.6	17.9	13.7	18.9	14.5	13.4	10.8	11.5	14.4	16.6	17.3	16.9	20.7	Bold figures are		Avg Ann'l P/E Ratio	18.0
.64	.78	.72	.72	.95	.74	1.00	.87	.89	.69	.72	.92	.93	.91	.85	1.08	Value Line		Relative P/E Ratio	1.15
3.9%	4.1%	3.9%	3.9%	3.4%	3.4%	2.7%	3.0%	3.5%	3.9%	4.0%	3.6%	3.3%	3.0%	3.0%	2.9%	estimates		Avg Ann'l Div'd Yield	3.7%

CAPITAL STRUCTURE as of 9/30/16
Total Debt $31677 mill. Due in 5 Yrs $14015 mill.
LT Debt $28195 mill. LT Interest $1241 mill.

(LT interest earned: 3.5x)

Pension Assets-12/15 $3563 mill.
Oblig $2403 mill.

Pfd Stock None

Common Stock 467,267,977 shs.

MARKET CAP: $58 billion (Large Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
15263	16410	15643	15317	15341	14256	15136	17021	17486	16155	17000	17700	Revenues ($mill)	20000
1312.0	1639.0	1615.0	1957.0	2021.0	1911.0	2062.0	2465.0	2752.0	2687	3320	3585	Net Profit ($mill)	4285
21.9%	21.5%	16.8%	21.4%	22.4%	26.6%	26.9%	32.3%	30.8%	29.3%	29.0%	29.0%	Income Tax Rate	29.0%
5.7%	6.6%	7.9%	4.4%	4.4%	10.8%	7.0%	3.5%	5.7%	6.0%	5.0%	5.0%	AFUDC % to Net Profit	5.0%
51.2%	54.2%	55.7%	55.5%	58.2%	59.1%	57.1%	55.0%	54.2%	53.5%	51.5%	50.5%	Long-Term Debt Ratio	47.5%
48.8%	45.8%	44.3%	44.5%	41.8%	40.9%	42.9%	45.0%	45.8%	46.5%	48.5%	49.5%	Common Equity Ratio	52.5%
22015	25514	29267	32474	35753	39245	42009	44283	49255	52150	55125	56875	Total Capital ($mill)	64000
28652	32411	36078	39075	42490	49413	52720	55705	61386	66912	70650	74525	Net Plant ($mill)	88300
7.5%	7.9%	6.9%	7.4%	7.0%	6.2%	6.2%	6.9%	6.7%	6.5%	7.0%	7.5%	Return on Total Cap'l	8.0%
12.2%	14.0%	12.5%	13.5%	13.5%	11.9%	11.4%	12.4%	12.2%	11.5%	12.5%	13.0%	Return on Shr. Equity	12.5%
12.2%	14.0%	12.5%	13.5%	13.5%	11.9%	11.4%	12.4%	12.2%	11.5%	12.5%	13.0%	Return on Com Equity E	12.5%
6.1%	7.9%	6.5%	7.8%	7.4%	5.6%	5.2%	6.0%	6.1%	4.5%	5.0%	4.5%	Retained to Com Eq	4.0%
50%	44%	47%	42%	46%	53%	54%	51%	50%	58%	58%	62%	All Div'ds to Net Prof	64%

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	+.9	+5.2	+5.6
Avg. Indust. Use (MWH)	296	294	277
Avg. Indust. Revs. per KWH (¢)	6.51	6.95	6.69
Capacity at Peak (Mw)	26236	27055	26073
Peak Load, Summer (Mw)	21576	22900	22717
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.8	+1.4	+1.4
Fixed Charge Cov. (%)	295	334	357

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '20-'22
Revenues	3.0%	-.5%	1.0%
"Cash Flow"	7.5%	6.0%	5.0%
Earnings	8.5%	5.0%	6.0%
Dividends	8.0%	8.5%	9.5%
Book Value	8.5%	7.5%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	3674	4029	4654	4664	17021
2015	4104	4358	4954	4070	17486
2016	3835	3817	4805	3698	16155
2017	4000	4200	4800	4000	17000
2018	4100	4400	5000	4200	17700

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.98	1.12	1.50	2.00	5.60
2015	1.45	1.59	1.93	1.10	6.06
2016	1.41	.93	1.62	1.82	5.78
2017	1.65	1.75	1.85	1.30	6.55
2018	1.75	1.85	1.95	1.40	6.95

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.66	.66	.66	.66	2.64
2014	.725	.725	.725	.725	2.90
2015	.77	.77	.77	.77	3.08
2016	.87	.87	.87	.87	3.48
2017					

BUSINESS: NextEra Energy, Inc. (formerly FPL Group, Inc.) is a holding company for Florida Power & Light Company (FPL), which provides electricity to 4.8 million customers in a 27,650-sq.-mi. area in eastern & southern Florida. NextEra Energy Resources is a non-regulated power generator with nuclear, gas, & wind ownership. Has a 79.9% stake in NextEra Energy Partners. Rev. breakdown: residential, 54%; commercial, 36%; industrial & other, 10%. Generating sources: gas, 69%; nuclear, 22%; coal, 4%; purchased, 5%. Fuel costs: 30% of revs. '15 reported depr. rate (utility): 3.3%. Has 13,800 employees. Chairman: Lewis Hay, III. President and CEO: James L. Robo. Inc.: FL. Address: 700 Universe Blvd., Juno Beach, FL 33408. Tel.: 561-694-4000. Internet: www.nexteraenergy.com.

NextEra Energy expects to complete the acquisition of Oncor in the first half of 2017. Oncor is a distribution utility with 3.3 million electric customers in Texas. However, its parent company is in bankruptcy protection, meaning the bankruptcy court as well as the Texas commission will have a say in whether the transaction gets approved. NextEra is paying $12 billion (mostly in cash) for Oncor. In anticipation of the deal's closing, the company has already begun issuing securities and selling assets to finance it. However, our estimates and projections will not include Oncor until after the acquisition has been completed.

The Florida commission approved Florida Power & Light's regulatory settlement. Rates rose $400 million at the start of 2017 and will climb another $211 million at the start of 2018. A $200 million hike will take effect in mid-2019 once a 1,748-megawatt gas-fired plant is completed. The allowed return on equity is 10.55%, with a range of 9.6%-11.6%.

We expect solid earnings growth in 2017 and 2018. The aforementioned rate increases will help. On the nonutility side, NextEra continues to enhance the company's earning power by adding contracted renewable-energy projects. Our 2017 and 2018 share-earnings estimates are within the company's targeted ranges of $6.35-$6.85 and $6.80-$7.30, respectively, which do not include Oncor. Note, however, that mark-to-market accounting items affect NextEra's quarterly and annual profits. We *include* these in our earnings presentation because they are an ongoing part of the company's results.

We believe the board of directors raised the dividend substantially shortly after our report went to press. We estimate an increase of $0.11 a share (12.6%) in the quarterly disbursement. NextEra's goal is 12%-14% annual dividend growth through at least 2018.

The earnings and dividend growth we project through 2020-2022 should produce a respectable total return over that time frame. What's more, investors do not have to sacrifice much current income for this long-term potential, as the dividend yield is only slightly below the utility norm.

Paul E. Debbas, CFA *February 17, 2017*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '02, (60¢); '03, 5¢; '11, (24¢); '13, (80¢); '16, 47¢; gain on discontinued ops.: '13, 44¢. '15 EPS don't add due to rounding. Next earnings report due late Apr. (B) Div'ds historically paid in mid-Mar., mid-June, mid-Sept., & mid-Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '15: $6.36/sh. (D) In mill., adj. for stock split. (E) Rate allowed on com. eq. in '17: 9.6%-11.6%; earned on avg. com. eq., '15: 12.9%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	70

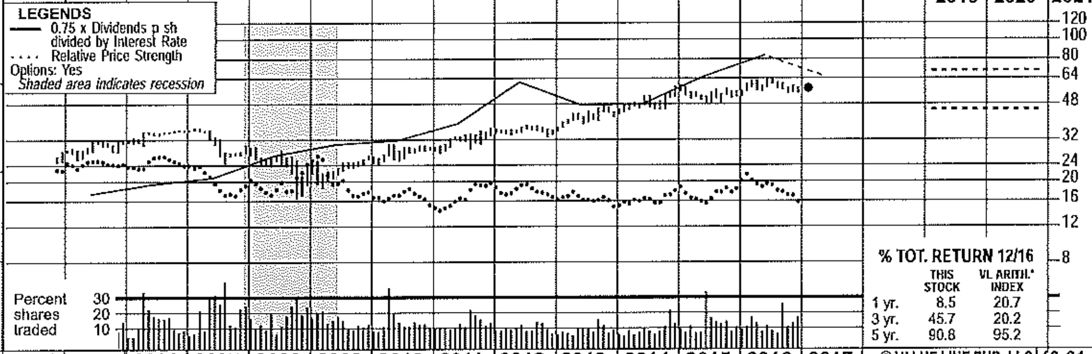
NORTHWESTERN NYSE-NWE

RECENT PRICE 57.34 | P/E RATIO 16.5 (Trailing: 17.0 Median: 16.0) | RELATIVE P/E RATIO 0.83 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 3 Raised 12/23/16
SAFETY 3 New 5/4/12
TECHNICAL 3 Raised 12/2/16
BETA .70 (1.00 = Market)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	32.5	35.8	36.7	29.7	26.8	30.6	36.6	38.0	47.2	58.7	59.7	63.8
Low:	25.5	30.1	24.5	16.5	18.5	23.8	27.4	33.0	35.1	42.6	48.4	52.2

LEGENDS
— 0.75 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+20%)	9%
Low	45	(-20%)	-1%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	11	0	4	0	0	3	0	0	3
to Sell	3	1	1	2	1	1	1	0	1

Institutional Decisions

	1Q2016	2Q2016	3Q2016
to Buy	109	114	105
to Sell	98	98	109
Hld's(000)	49010	48537	47339

% TOT. RETURN 12/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	8.5	20.7
3 yr.	45.7	20.2
5 yr.	90.8	95.2

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
--	--	--	--	29.18	32.57	31.49	30.79	35.09	31.72	30.66	30.80	28.76	29.80	25.68	25.21	*25.75*	*26.65*	Revenues per sh	*30.25*
--	--	--	--	3.20	4.00	3.62	3.70	4.40	4.62	4.76	5.42	5.18	5.45	5.39	5.92	*6.60*	*6.85*	"Cash Flow" per sh	*8.00*
--	--	--	--	d14.32	1.71	1.31	1.44	1.77	2.02	2.14	2.53	2.26	2.46	2.99	2.90	*3.40*	*3.45*	Earnings per sh A	*4.00*
--	--	--	--	--	1.00	1.24	1.28	1.32	1.34	1.36	1.44	1.48	1.52	1.60	1.92	2.00	*2.08*	Div'd Decl'd per sh B ■ †	*2.32*
--	--	--	--	2.25	2.26	2.81	3.00	3.47	5.26	6.30	5.20	5.89	5.95	5.76	5.89	*6.35*	*6.65*	Cap'l Spending per sh	*5.50*
--	--	--	--	19.92	20.60	20.65	21.12	21.25	21.86	22.64	23.68	25.09	26.60	31.50	33.22	*34.40*	*35.60*	Book Value per sh C	*40.25*
--	--	--	--	35.60	35.79	35.97	38.97	35.93	36.00	36.23	36.28	37.22	38.75	46.91	48.17	*48.50*	*48.75*	Common Shs Outst'g D	*49.50*
--	--	--	--	--	17.1	26.0	21.7	13.9	11.5	12.9	12.6	15.7	16.9	16.2	18.4	*17.1*		Avg Ann'l P/E Ratio	*14.0*
--	--	--	--	--	.91	1.40	1.15	.84	.77	.82	.79	1.00	.95	.85	.93	*.90*		Relative P/E Ratio	*.90*
--	--	--	--	--	3.4%	3.6%	4.1%	5.4%	5.7%	4.9%	4.5%	4.2%	3.7%	3.3%	3.6%	*3.4%*		Avg Ann'l Div'd Yield	*4.1%*

CAPITAL STRUCTURE as of 9/30/16
Total Debt $2043.6 mill. Due in 5 Yrs $477.6 mill.
LT Debt $1819.4 mill. LT Interest $83.7 mill.
Incl. $25.4 mill. capitalized leases.
(LT interest earned: 2.9x)

Pension Assets-12/15 $500.0 mill.
Oblig. $628.9 mill.

Pfd Stock None

Common Stock 48,327,642 shs.
as of 10/14/16
MARKET CAP: $2.8 billion (Mid Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
1132.7	1200.1	1260.8	1141.9	1110.7	1117.3	1070.3	1154.5	1204.9	1214.3	*1250*	*1300*	Revenues ($mill)	*1500*
49.2	53.2	67.6	73.4	77.4	92.6	83.7	94.0	120.7	138.4	*165*	*170*	Net Profit ($mill)	*200*
40.3%	37.8%	37.3%	17.2%	25.0%	9.8%	9.6%	13.2%	13.2%	13.7%	*Nil*	*12.0%*	Income Tax Rate	*20.0%*
3.3%	2.5%	2.3%	7.2%	22.7%	5.4%	15.2%	14.1%	14.4%	16.1%	*9.0%*	*9.0%*	AFUDC % to Net Profit	*5.0%*
49.9%	50.1%	46.8%	56.4%	57.2%	52.2%	53.8%	53.5%	53.4%	53.1%	*54.0%*	*53.0%*	Long-Term Debt Ratio	*50.5%*
50.1%	49.9%	53.2%	43.6%	42.8%	47.8%	46.2%	46.5%	46.6%	46.9%	*46.0%*	*47.0%*	Common Equity Ratio	*49.5%*
1482.2	1648.4	1434.3	1803.9	1916.4	1797.1	2020.7	2215.7	3168.0	3408.6	*3630*	*3700*	Total Capital ($mill)	*4000*
1491.9	1770.9	1839.7	1964.1	2118.0	2213.3	2435.6	2690.1	3758.0	4059.5	*4215*	*4375*	Net Plant ($mill)	*4850*
5.2%	5.0%	7.0%	6.0%	6.0%	7.1%	5.5%	5.5%	4.8%	5.2%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
6.6%	6.5%	8.9%	9.3%	9.4%	10.8%	9.0%	9.1%	8.2%	8.6%	*10.0%*	*9.5%*	Return on Shr. Equity	*10.0%*
6.6%	6.5%	8.9%	9.3%	9.4%	10.8%	9.0%	9.1%	8.2%	8.6%	*10.0%*	*9.5%*	Return on Com Equity E	*10.0%*
.7%	.7%	2.3%	3.2%	3.5%	4.7%	3.2%	3.5%	3.8%	3.0%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
90%	89%	74%	66%	63%	56%	65%	61%	54%	65%	*59%*	*60%*	All Div'ds to Net Prof	*58%*

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	+1.3	+.7	-.1
Avg. Indust. Use (MWH)	29162	28987	30133
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	2056	2044	2096
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.7	+1.0	+1.3
Fixed Charge Cov. (%)	217	201	232

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	-1.5%	-3.5%	2.0%
"Cash Flow"	4.5%	4.0%	6.0%
Earnings	--	7.0%	6.5%
Dividends	13.0%	4.5%	5.5%
Book Value	4.0%	7.0%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	313.0	260.2	262.2	319.1	1154.5
2014	369.7	270.3	251.9	313.0	1204.9
2015	346.0	270.6	272.7	325.0	1214.3
2016	332.5	293.1	301.0	*323.4*	*1250*
2017	*350*	*310*	*310*	*330*	*1300*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	1.01	.37	.40	.68	2.46
2014	1.17	.20	.77	.85	2.99
2015	1.09	.38	.51	.93	2.90
2016	.79	.73	.92	*.96*	*3.40*
2017	*1.10*	*.50*	*.75*	*1.10*	*3.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.38	.38	.38	.38	1.52
2014	.40	.40	.40	.40	1.60
2015	.48	.48	.48	.48	1.92
2016	.50	.50	.50	.50	2.00
2017					

BUSINESS: NorthWestern Corporation (doing business as NorthWestern Energy) supplies electricity & gas in the Upper Midwest and Northwest, serving 422,000 electric customers in Montana and South Dakota and 279,000 gas customers in Montana (87% of gross margin), South Dakota (12%), and Nebraska (1%). Electric revenue breakdown: residential, 40%; commercial, 51%; industrial, 5%; other, 4%. Generating sources are not provided by company. Fuel costs: 31% of revenues. '15 reported depreciation rate: 3.3%. Has 1,600 employees. Chairman: Dr. E. Linn Draper Jr. President & CEO: Robert C. Rowe. Incorporated: Delaware. Address: 3010 West 69th Street, Sioux Falls, South Dakota 57108. Telephone: 605-978-2900. Internet: www.northwesternenergy.com.

NorthWestern has a gas rate case pending in Montana. The utility is seeking a return on the capital expenditures and gas reserves it has made since 2012 (the year of its last rate case). NorthWestern filed for a hike of $10.9 million (8.0%), based on a 10.35% return on a 46.8% common-equity ratio. A ruling from the Montana Public Service Commission (MPSC) is expected in mid-2017. The utility is also seeking an interim tariff increase of $5.6 million (4.9%). When the MPSC will rule on the interim request is unknown.

The company has some legal matters pending, as well. NorthWestern has taken the Federal Reserve Energy Commission (FERC) to the U.S. Circuit Court of Appeals. FERC had ruled that just 4% of the cost of a new gas-fired generating facility could be allocated to wholesale customers. NorthWestern wants an allocation of 20%, with the other 80% allocated to the company's customers in Montana. This resulted in a $0.12-a-share charge (included in our earnings presentation) in 2012. A ruling is unlikely before the second half of 2017, and might come mucb later than that. NorthWestern asked FERC to reconsider, but was unsuccessful. Separately, the utility appealed to the Montana District Court after the MPSC disallowed some costs stemming from a plant outage in 2013. This forced NorthWestern to take a $0.13-a-share charge (included in our presentation) in the first period of 2016. It will likely be several more months—perhaps not until 2018—before a ruling is received.

We estimate that earnings will increase slightly in 2017. NorthWestern should benefit from rate relief and customer growth. Our $3.45-a-share profit estimate is within the company's preliminary guidance of $3.30-$3.50.

We expect a dividend hike in the current quarter. This has been the board's practice. We estimate a raise of two cents a share (4%) in the quarterly payout.

NorthWestern stock has a dividend yield that is about equal to the utility average. With the recent quotation near the midpoint of our 2019-2021 Target Price Range, total return potential over that time frame is unspectacular.

Paul E. Debbas, CFA *January 27, 2017*

(A) Diluted EPS. Excl. gain (loss) on disc. ops.: '05, (6¢); '06, 1¢; nonrec. gains: '12, 39¢ net; '15, 27¢. '15 EPS don't add due to rounding. Next earnings report due mid-Feb. (B) Div'ds historically paid in late Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. def'd charges. In '15: $18.16/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in MT in '14 (elec.): 9.8%; in '13 (gas): 9.8%; in SD in '15: none spacified; in NE in '07: 10.4%; earned on avg. com. eq., '15: 9.0%. Regul. Climate: Avg.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	85
Earnings Predictability	90

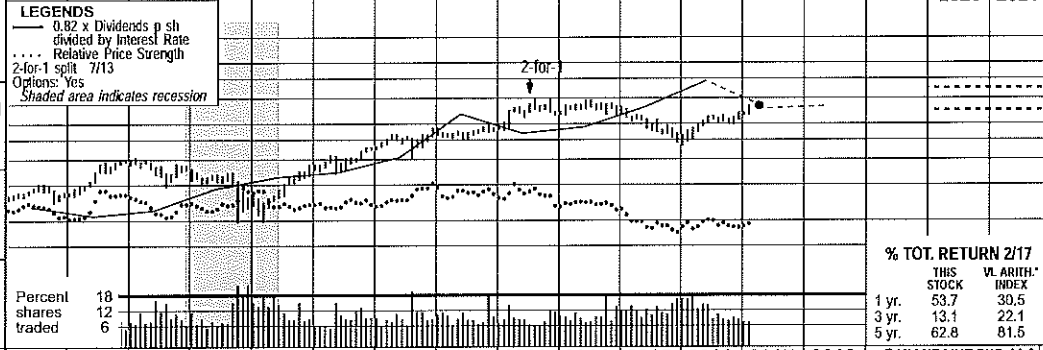
OGE ENERGY CORP. NYSE-OGE

RECENT PRICE 36.80 | P/E RATIO 18.0 (Trailing: 21.8 Median: 15.0) | RELATIVE P/E RATIO 0.92 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 3 Lowered 3/3/17
SAFETY 2 Lowered 12/18/15
TECHNICAL 4 Lowered 3/17/17
BETA .95 (1.00 = Market)

High:	20.3	20.7	18.1	18.9	23.1	28.6	30.1	40.0	39.3	36.5	34.2	37.4
Low:	13.2	14.6	9.8	9.9	16.9	20.3	25.1	27.7	32.8	24.2	23.4	32.8

Target Price Range
2020 | 2021 | 2022



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+20%)	9%
Low	35	(-5%)	3%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	0	1	1	0	0	0	0

Institutional Decisions

	2Q2016	3Q2016	4Q2016
to Buy	178	158	195
to Sell	142	152	156
Hld's(000)	129725	132580	131802

% TOT. RETURN 2/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	53.7	30.5
3 yr.	13.1	22.1
5 yr.	62.8	81.5

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
20.40	19.26	21.62	27.37	32.83	21.96	20.68	21.77	14.79	19.04	19.96	18.58	14.45	12.30	11.00	11.31	*11.75*	*12.25*	Revenues per sh	*14.50*
1.81	1.87	1.82	1.87	1.94	2.23	2.39	2.40	2.69	3.01	3.31	3.69	3.46	3.40	3.23	3.31	*3.75*	*3.85*	"Cash Flow" per sh	*4.50*
.65	.72	.87	.89	.92	1.23	1.32	1.25	1.33	1.50	1.73	1.79	1.94	1.98	1.69	1.69	*2.05*	*2.10*	Earnings per sh A	*2.50*
.67	.67	.67	.67	.67	.67	.68	.70	.71	.73	.76	.80	.85	.95	1.05	1.16	*1.27*	*1.40*	Div'd Decl'd per sh B ■	*1.75*
1.44	1.49	1.04	1.51	1.65	2.67	3.04	4.01	4.37	4.36	6.48	5.85	4.99	2.86	2.74	3.31	*5.00*	*2.85*	Cap'l Spending per sh	*2.50*
6.67	6.27	6.87	7.14	7.59	8.79	9.16	10.14	10.52	11.73	13.06	14.00	15.30	16.27	16.66	17.24	*18.05*	*18.80*	Book Value per sh C	*20.75*
155.98	157.00	174.80	180.00	181.20	182.40	183.60	187.00	194.00	195.20	196.20	197.60	198.50	199.40	199.70	199.70	*199.70*	*200.00*	Common Shs Outst'g D	*201.50*
17.4	14.1	11.8	14.1	14.9	13.7	13.8	12.4	10.8	13.3	14.4	15.2	17.7	18.3	17.7	17.7	*Bold figures are*		Avg Ann'l P/E Ratio	*16.5*
.89	.77	.67	.74	.79	.74	.73	.75	.72	.85	.90	.97	.99	.96	.89	.93	*Value Line*		Relative P/E Ratio	*1.05*
5.9%	6.6%	6.5%	5.3%	4.9%	4.0%	3.8%	4.5%	5.0%	3.7%	3.1%	2.9%	2.5%	2.6%	3.5%	3.9%	*estimates*		Avg Ann'l Div'd Yield	*4.3%*

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
3797.6	4070.7	2869.7	3716.9	3915.9	3671.2	2867.7	2453.1	2196.9	2259.2	*2350*	*2450*	Revenues ($mill)	*2900*
244.2	231.4	258.3	295.3	342.9	355.0	387.6	395.8	337.6	338.2	*410*	*425*	Net Profit ($mill)	*495*
32.3%	30.4%	31.7%	34.9%	30.7%	26.0%	24.9%	30.4%	29.2%	30.5%	*32.0%*	*32.0%*	Income Tax Rate	*32.0%*
1.6%	1.7%	9.1%	5.7%	9.0%	2.7%	2.6%	1.7%	3.7%	6.4%	*12.0%*	*7.0%*	AFUDC % to Net Profit	*3.0%*
44.4%	53.3%	50.6%	50.8%	51.6%	50.7%	43.1%	45.9%	44.3%	41.1%	*43.0%*	*45.0%*	Long-Term Debt Ratio	*51.0%*
55.6%	46.7%	49.4%	49.2%	48.4%	49.3%	56.9%	54.1%	55.7%	58.9%	*57.0%*	*55.0%*	Common Equity Ratio	*49.0%*
3025.5	4058.6	4129.7	4652.5	5300.4	5615.8	5337.2	5999.7	5971.6	5849.6	*6315*	*6815*	Total Capital ($mill)	*8600*
4246.3	5249.8	5911.6	6464.4	7474.0	8344.8	6672.8	6979.9	7322.4	7696.2	*8360*	*8585*	Net Plant ($mill)	*8900*
9.5%	7.0%	7.9%	7.8%	7.8%	7.7%	8.6%	7.8%	6.9%	7.0%	*7.5%*	*7.5%*	Return on Total Cap'l	*7.0%*
14.5%	12.2%	12.7%	12.9%	13.4%	12.8%	12.8%	12.2%	10.2%	9.8%	*11.5%*	*11.0%*	Return on Shr. Equity	*12.0%*
14.5%	12.2%	12.7%	12.9%	13.4%	12.8%	12.8%	12.2%	10.2%	9.8%	*11.5%*	*11.0%*	Return on Com Equity E	*12.0%*
7.1%	5.4%	6.0%	6.7%	7.7%	7.2%	7.3%	6.5%	4.0%	3.3%	*4.5%*	*4.0%*	Retained to Com Eq	*3.5%*
51%	55%	53%	48%	43%	44%	43%	47%	61%	67%	*62%*	*66%*	All Div'ds to Net Prof	*71%*

CAPITAL STRUCTURE as of 12/31/16
Total Debt $2866.7 mill. Due in 5 Yrs $961.3 mill.
LT Debt $2405.8 mill. LT Interest $130.7 mill.
(LT interest earned: 4.2x)

Leases, Uncapitalized Annual rentals $6.0 mill.

Pension Assets-12/16 $595.9 mill. Oblig $672.2 mill.

Pfd Stock None

Common Stock 199,703,952 shs. as of 1/31/17
MARKET CAP: $7.3 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	-.7	-2.9	-1.1
Avg. Indust. Use (MWH)	770	754	NA
Avg. Indust. Revs. per KWH (¢)	5.73	5.05	5.17
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	6339	6537	6538
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	+1.2	+1.1
Fixed Charge Cov. (%)	356	314	336

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	-8.5%	-8.5%	*4.0%*
"Cash Flow"	5.0%	2.0%	*5.5%*
Earnings	6.0%	3.5%	*5.5%*
Dividends	4.5%	7.5%	*9.0%*
Book Value	8.0%	7.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	560.4	611.8	754.7	526.2	2453.1
2015	480.1	549.9	719.8	447.1	2196.9
2016	433.1	551.4	743.9	530.8	2259.2
2017	*500*	*600*	*750*	*500*	*2350*
2018	*525*	*600*	*800*	*525*	*2450*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.25	.50	.94	.29	1.98
2015	.22	.44	.88	.15	1.69
2016	.13	.35	.92	.29	1.69
2017	*.23*	*.52*	*1.00*	*.30*	*2.05*
2018	*.25*	*.50*	*1.05*	*.30*	*2.10*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.209	.209	.209	.209	.84
2014	.225	.225	.225	.25	.93
2015	.25	.25	.25	.275	1.03
2016	.275	.275	.275	.3025	1.13
2017	.3025				

BUSINESS: OGE Energy Corp. is a holding company for Oklahoma Gas and Electric Company (OG&E), which supplies electricity to 834,000 customers in Oklahoma (84% of electric revenues) and western Arkansas (8%); wholesale is (8%). Owns 25.7% of Enable Midstream Partners. Electric revenue breakdown: residential, 42%; commercial, 25%; industrial, 15%; other, 18%. Generating sources: coal, 33%; gas, 31%; wind, 5%; purchased, 31%. Fuel costs: 39% of revenues. '16 reported depreciation rate (utility): 3.0%. Has 2,500 employees. Chairman, President and Chief Executive Officer: Sean Trauschke. Incorporated: Oklahoma. Address: 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321. Telephone: 405-553-3000. Internet: www.oge.com.

OGE Energy's utility subsidiary is still awaiting an order on its rate case in Oklahoma. Oklahoma Gas and Electric is seeking a rate hike of $92.5 million, based on a return of 10.25% on a common-equity ratio of 53.5%. OG&E wants to recover higher costs, place capital spending in the rate base, and place a generating unit back in rates. This plant was removed from the rate base while being used to serve a wholesale power contract that expired. An administrative law judge is recommending a $41 million tariff hike, based on a 9.87% ROE. The staff of the Oklahoma Corporation Commission (OCC) and the state attorney general's office are proposing an allowed ROE of just 9.25%. The utility expects an order from the OCC soon. This will be retroactive to July 1, 2016.

OG&E is also awaiting a rate decision in Arkansas. The utility requested $16.5 million, based on a 10.25% return on a 53% common-equity ratio. OG&E also asked to initiate a formula rate plan, which would allow the company to recover certain costs without filing a general rate application. An order is expected in June.

Earnings will probably rise significantly this year. Modest volume growth and rate relief (including the portion that is retroactive to 2016) are the key factors. OGE's stake in Enable Midstream Partners, a midstream gas master limited partnership, will help as commodity prices recover. We have raised our earnings estimate by $0.15 a share, to $2.05. Our revised estimate is near the upper end of OGE's targeted range of $1.93-$2.09 a share. We forecast a more-modest growth rate in 2018, as the utility won't have the extra benefit of the income from the rate case that would have been booked in 2016 had the OCC issued its order that year.

The price of OGE stock has risen 10% so far this year. This makes this issue one of the top performers among electric companies. We think investors are heartened by the improved prospects at Enable; note that CenterPoint Energy, another owner of Enable, is up 14% in 2017. We project OGE will produce a respectable total return over the 2020-2022 period, helped by 10% annual dividend growth through 2019.

Paul E. Debbas, CFA *March 17, 2017*

(A) Diluted EPS. Excl. nonrecurring losses: '02, 20¢; '03, 7¢; '04, 3¢; '15, 33¢; gains on discontinued operations: '02, 6¢; '05, 25¢; '06, 20¢. Next earnings report due early May. (B) Div'ds historically paid in late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan available. (C) Incl. deferred charges. In '16: $2.03/sh. (D) In millions, adj. for split. (E) Rate base: Net original cost. Rate allowed on com. eq. in OK in '12: 10.2%; in AR in '11: 9.95%; earned on avg. com. eq., '16: 10.0%. Regulatory Climete: Average.

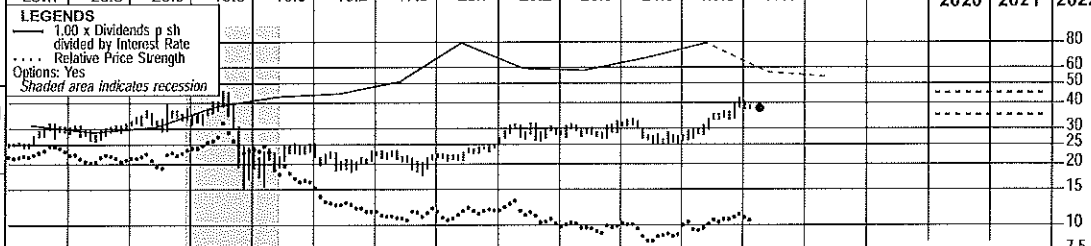
Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	65
Earnings Predictability	80

OTTER TAIL CORP. NDQ-OTTR

RECENT PRICE 37.70 | P/E RATIO 22.4 (Trailing: 23.6; Median: 23.0) | RELATIVE P/E RATIO 1.15 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 3 Lowered 10/14/16
SAFETY 2 Raised 6/17/16
TECHNICAL 2 Lowered 2/17/17
BETA .85 (1.00 = Market)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
High:	31.9	39.4	46.2	25.4	25.4	23.5	25.3	31.9	32.7	33.4	42.6	40.8
Low:	25.8	29.0	15.0	15.5	18.2	17.5	20.7	25.2	26.5	24.8	25.8	37.1



Target Price Range 2020 | 2021 | 2022

2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+20%)	7%
Low	35	(-5%)	2%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	2	0	0	1	0	1

Institutional Decisions

	2Q2016	3Q2016	4Q2016
to Buy	68	80	65
to Sell	44	45	57
Hld's(000)	13887	14545	15287

% TOT. RETURN 2/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	42.5	30.5
3 yr.	40.7	22.1
5 yr.	119.2	81.5

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
26.53	27.75	29.28	30.45	35.59	37.43	41.50	37.06	29.03	31.08	29.86	23.76	24.63	21.48	20.60	20.42	*21.00*	*21.35*	Revenues per sh	*25.00*
3.40	3.44	3.30	2.88	3.35	3.39	3.55	2.81	2.76	2.60	2.36	2.71	3.02	3.09	3.14	3.44	*3.65*	*3.90*	"Cash Flow" per sh	*4.75*
1.68	1.79	1.51	1.50	1.78	1.69	1.78	1.09	.71	.38	.45	1.05	1.37	1.55	1.56	1.60	*1.68*	*1.75*	Earnings per sh A	*2.20*
1.04	1.06	1.08	1.10	1.12	1.15	1.17	1.19	1.19	1.19	1.19	1.19	1.19	1.21	1.23	1.25	*1.28*	*1.30*	Div'd Decl'd per sh B ■	*1.38*
2.17	2.95	1.97	1.72	2.04	2.35	5.43	7.51	4.95	2.38	2.04	3.20	4.53	4.40	4.23	4.10	*3.75*	*4.65*	Cap'l Spending per sh	*2.10*
11.33	12.25	12.98	14.81	15.80	16.67	17.55	19.14	18.78	17.57	15.83	14.43	14.75	15.39	15.98	17.03	*18.25*	*19.25*	Book Value per sh C	*23.20*
24.65	25.59	25.72	28.98	29.40	29.52	29.85	35.38	35.81	36.00	36.10	36.17	36.27	37.22	37.86	39.35	*40.00*	*41.00*	Common Shs Outst'g D	*44.00*
16.4	16.0	17.8	17.3	15.4	17.3	19.0	30.1	31.2	55.1	47.5	21.7	21.1	18.8	18.2	20.2	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.84	.87	1.01	.91	.82	.93	1.01	1.81	2.08	3.51	2.98	1.38	1.19	.99	.92	1.06	*Value Line*		Relative P/E Ratio	*1.15*
3.8%	3.7%	4.0%	4.2%	4.1%	3.9%	3.5%	3.6%	5.4%	5.7%	5.6%	5.2%	4.1%	4.1%	4.3%	3.9%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 12/31/16
Total Debt $581.4 mill. Due in 5 Yrs $232.0 mill.
LT Debt $505.3 mill. LT Interest $28.0 mill.
(LT interest earned: 3.6x)

Leases, Uncapitalized Annual rentals $7 mill.
Pension Assets-12/16 $254.3 mill. Oblig. $314.6 mill.
Pfd Stock None

Common Stock 39,410,825 shs. as of 2/10/17
MARKET CAP: $1.5 billion (Mid Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
1238.9	1311.2	1039.5	1119.1	1077.9	859.2	893.3	799.3	779.8	803.5	*840*	*875*	Revenues ($mill)	*1100*
54.0	35.1	26.0	13.6	16.4	39.0	50.2	56.9	58.6	62.0	*65.0*	*70.0*	Net Profit ($mill)	*95.0*
34.1%	30.0%	--	--	14.5%	5.2%	21.3%	22.5%	27.0%	24.5%	*25.0%*	*25.0%*	Income Tax Rate	*30.0%*
4.2%	6.1%	4.0%	.6%	3.8%	1.7%	--	--	1.7%	3.6%	*3.0%*	*4.0%*	AFUDC % to Net Profit	*5.0%*
38.9%	32.9%	38.8%	40.2%	44.6%	44.0%	42.1%	46.5%	42.4%	43.0%	*42.0%*	*41.0%*	Long-Term Debt Ratio	*40.0%*
59.4%	65.6%	59.8%	58.4%	54.0%	54.4%	57.9%	53.5%	57.6%	57.0%	*58.0%*	*59.0%*	Common Equity Ratio	*60.0%*
882.1	1032.5	1124.4	1083.3	1058.9	959.2	924.4	1071.3	1051.0	1175.4	*1255*	*1340*	Total Capital ($mill)	*1695*
854.0	1037.6	1098.6	1108.7	1077.5	1049.5	1167.0	1268.5	1387.8	1477.2	*1575*	*1700*	Net Plant ($mill)	*1950*
7.2%	4.3%	3.4%	2.7%	3.2%	5.7%	6.7%	6.7%	6.7%	6.5%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
10.0%	5.1%	3.8%	2.1%	2.8%	7.3%	9.4%	9.9%	9.7%	9.3%	*9.0%*	*9.0%*	Return on Shr. Equity E	*9.5%*
10.2%	5.1%	3.8%	2.0%	2.7%	7.3%	9.3%	9.9%	9.7%	9.3%	*9.0%*	*9.0%*	Return on Com Equity	*9.5%*
3.5%	NMF	NMF	NMF	NMF	NMF	1.2%	2.2%	2.0%	2.1%	*2.0%*	*2.0%*	Retained to Com Eq	*3.5%*
66%	108%	NMF	NMF	NMF	113%	87%	78%	79%	78%	*80%*	*77%*	All Div'ds to Net Prof	*65%*

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+4.6	-2.2	3.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	336	350	348

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	-5.0%	-7.0%	2.5%
"Cash Flow"	--	4.5%	4.5%
Earnings	-0.5%	25.0%	5.0%
Dividends	1.0%	0.5%	1.5%
Book Value	--	-1.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	215.0	194.4	196.5	193.4	799.3
2015	202.8	188.2	200.0	188.8	779.8
2016	206.2	203.5	197.2	196.6	803.5
2017	*212*	*208*	*210*	*210*	*840*
2018	*220*	*215*	*220*	*220*	*875*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.59	.27	.43	.28	1.55
2015	.37	.36	.42	.41	1.56
2016	.38	.41	.37	.44	1.60
2017	*.42*	*.40*	*.42*	*.44*	*1.68*
2018	*.44*	*.41*	*.44*	*.46*	*1.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.298	.298	.298	.298	1.19
2014	.303	.303	.303	.303	1.21
2015	.308	.308	.308	.308	1.23
2016	.313	.313	.313	.313	1.25
2017	.320				

BUSINESS: Otter Tail Corporation is the parent of Otter Tail Power Company, which supplies electricity to over 130,000 customers in Minnesota (53% of retail elec. revs.), North Dakota (38%), and South Dakota (9%). Electric rev. breakdown, '16: residential, 31%; commercial & farms, 36%; industrial, 31%; other, 2%. Fuel costs: 14.7% of revenues. Also has operations in manufacturing and plastics. 2015 depr. rate: 3.3%. Has 2,054 employees. Off. and dir. own 1.4% of common stock; Cascade Investment, LLC, 8.8%; The Vanguard Group, 8.3%; BlackRock, Inc., 6.3% (3/17 Proxy). CEO: Charles MacFarlane. Inc.: MN. Address: 215 South Cascade St., P.O. Box 496, Fergus Falls, Minnesota 56538-0496. Telephone: 866-410-8780. Internet: www.ottertail.com.

Shares of Otter Tail have traded in a narrow range lately, following a strong advance in price during 2016. The company posted moderate growth for the fourth quarter. The Electric segment benefited from an interim rate increase in Minnesota, greater rider revenues, and higher sales to commercial and industrial customers. Meanwhile, the Plastics business reported a greater volume of pipe sold, though pricing remained soft. Overall, earnings were supported by a lower tax rate.

The board has increased the dividend roughly 2%. Starting with the March payout, the quarterly dividend is now $0.32 per share. Modest dividend growth will probably continue in the coming years.

We expect solid performance by the company going forward. A return to normal weather this year would support performance at the Electric business. A constructive outcome for the rate case filed in February of 2016 would also help, assuming that interim rates obtained become final. Major projects here in 2017 include planned expenditures for investment in two large transmission lines. These positively impact the bottom line by providing an immediate return on invested funds through rider recovery mechanisms. Higher sales to pipeline and commercial customers should also boost results at the Electric segment. Increased operating costs will likely be a partial offset. Meanwhile, the Manufacturing line should benefit from greater sales from the lawn and garden, as well as the horticulture and custom, end markets. Softness may well continue in other areas, but we expect improved productivity at subsidiary BTD. Elsewhere, earnings at the Plastics business may well remain flat this year. Sales prices are expected to strengthen, though volumes will probably decline in the southern California and Texas markets.

Long-term appreciation potential is subpar. Solid growth prospects appear to be partly reflected in the recent quotation. In the plus column, this issue offers a healthy dividend yield. Moreover, Otter Tail earns good marks for Safety, Financial Strength, and Price Stability. A pullback in the share price may offer prospective investors a better entry point.

Michael Napoli, CFA *March 17, 2017*

(A) Diluted earnings. Excl. nonrecurring gains (losses): '10, (44¢); '11, 26¢; '13, 2¢; gains (losses) from discont. operations: '04, 8¢; '05, 33¢; '06, 1¢; '11, ($1.11); '12, ($1.22); '13, 2¢; '14, 2¢; '15, 2¢; '16, 1¢. Earnings may not sum due to rounding. Next earnings report due early May. (B) Div'ds historically paid in early March, June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. intangibles. In '16: $52.5 mill., $1.34/sh. (D) In mill. (E) Regulatory Climate: MN, ND, Average; SD, Above Average.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	20
Earnings Predictability	50

PEPCO HOLDINGS NYSE-POM

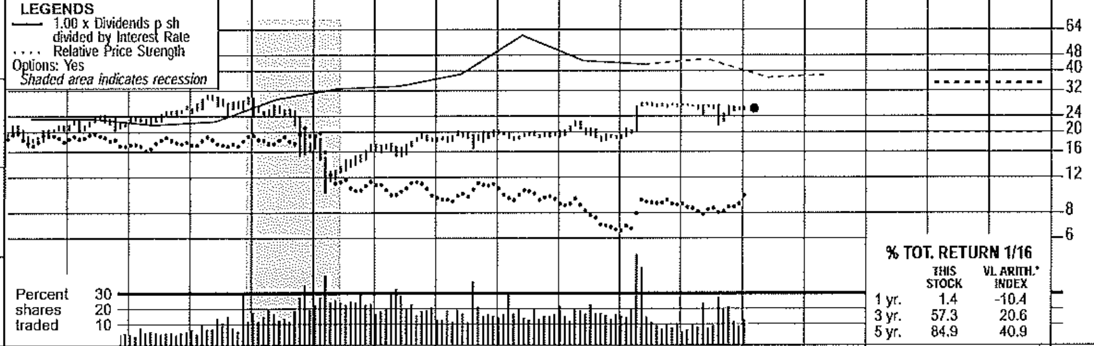
RECENT PRICE 26.20 | P/E RATIO 23.4 (Trailing: 28.5 / Median: 16.0) | RELATIVE P/E RATIO 1.45 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS – Suspended 5/9/14
SAFETY 3 Lowered 6/6/03
TECHNICAL – Suspended 5/9/14
BETA .75 (1.00 = Market)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	24.5	27.0	30.7	29.6	18.7	19.8	20.6	20.5	22.7	27.9	27.5	26.8
Low:	20.3	21.8	24.2	15.3	10.1	15.1	16.6	18.1	18.0	18.5	21.6	25.6

Target Price Range
2019 | 2020 | 2021

LEGENDS
—— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+35%)	11%
Low	20	(-25%)	-7%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2015	2Q2015	3Q2015
to Buy	151	140	156
to Sell	156	168	141
Hld's(000)	158602	160730	160867

% TOT. RETURN 1/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.4	-10.4
3 yr.	57.3	20.6
5 yr.	84.9	40.9

Pepco Holdings, Inc. (PHI) was formed on August 1, 2002, upon the merger of Potomac Electric Power Co. (PEPCO) and Conectiv. In the $2.2 billion deal, PEPCO common stockholders received one common share in PHI for each of their shares, and Conectiv investors exchanged each of their common shares for $25 worth of PHI stock and cash, prorated 50/50.

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
43.57	46.71	48.88	41.66	31.27	26.02	22.09	18.64	19.49	19.70	20.85	22.25	Revenues per sh	26.15
3.47	3.30	3.55	2.82	2.97	3.00	3.21	3.01	3.16	3.35	3.40	3.50	"Cash Flow" per sh	4.30
1.33	1.53	1.93	1.06	1.24	1.14	1.24	1.14	.96	1.05	1.15	1.22	Earnings per sh A	2.00
1.04	1.04	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08	Div'd Decl'd per sh B ■	1.08
2.47	3.11	3.57	3.89	3.56	4.14	5.29	5.23	4.89	5.20	5.20	5.00	Cap'l Spending per sh	4.00
18.82	20.04	19.14	19.15	18.79	19.06	19.33	17.24	17.27	18.10	18.45	18.60	Book Value per sh C	20.30
191.93	200.51	218.91	222.27	225.08	227.50	230.02	250.32	250.32	254.00	254.00	254.00	Common Shs Outst'g D	260.00
18.1	18.2	12.2	13.7	14.0	16.7	15.6	17.5	26.0	25.1	Bold figures are		Avg Ann'l P/E Ratio	14.0
.98	.97	.73	.91	.89	1.05	.99	.98	1.37	1.27	Value Line		Relative P/E Ratio	.90
4.3%	3.7%	4.6%	7.4%	6.2%	5.7%	5.6%	5.4%	4.3%	4.1%	estimates		Avg Ann'l Div'd Yield	3.9%
8362.9	9366.4	10700	9259.0	7039.0	5920.0	5081.0	4666.0	4878.0	5000	5400	5650	Revenues ($mill)	6700
254.4	296.5	400.0	235.0	276.0	257.0	285.0	280.0	242.0	280	300	320	Net Profit ($mill)	525
39.1%	39.3%	29.6%	31.9%	18.8%	37.2%	35.4%	35.3%	36.3%	35.0%	35.0%	35.0%	Income Tax Rate	35.0%
--	--	--	--	--	10.1%	7.4%	6.4%	8.3%	6.0%	5.0%	5.0%	AFUDC % to Net Profit	4.0%
54.6%	54.1%	56.2%	53.8%	49.0%	49.1%	47.3%	48.4%	50.7%	51.0%	52.0%	52.5%	Long-Term Debt Ratio	53.0%
45.1%	45.9%	43.8%	46.2%	51.0%	50.9%	52.7%	51.6%	49.3%	49.5%	48.0%	47.5%	Common Equity Ratio	47.0%
8004.0	8753.0	9568.0	9203.0	8292.0	8516.0	8432.0	8368.0	8763.0	9505	9875	9900	Total Capital ($mill)	11215
7576.6	7876.7	8314.0	8863.0	7673.0	8220.0	8846.0	9704.0	10506	10000	10500	10700	Net Plant ($mill)	12000
5.1%	5.1%	5.8%	4.5%	5.1%	4.5%	4.9%	4.9%	4.2%	5.0%	5.0%	5.5%	Return on Total Cap'l	6.0%
7.0%	7.4%	9.5%	5.5%	6.5%	5.9%	6.4%	6.5%	5.6%	8.0%	8.0%	8.0%	Return on Shr. Equity	10.0%
7.0%	7.4%	9.5%	5.5%	6.5%	5.9%	6.4%	6.5%	5.6%	8.0%	8.0%	8.0%	Return on Com Equity E	10.0%
1.5%	2.3%	4.2%	NMF	.8%	.3%	.8%	.2%	NMF	2.1%	2.3%	2.5%	Retained to Com Eq	4.5%
78%	68%	56%	101%	87%	95%	87%	96%	112%	105%	94%	89%	All Div'ds to Net Prof	53%

CAPITAL STRUCTURE as of 9/30/15
Total Debt $6467 mill. Due in 5 Yrs $1196 mill.
LT Debt $5028 mill. LT Interest $260 mill.
(LT interest earned: 3.7x)

Pension Assets-12/14 $2.0 bill. Oblig. $2.2 bill.

Pfd Stock None

Common Stock 253,617,191 shs.
as of 10/16/15

MARKET CAP: $6.6 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	NA	NA	NA
Avg. Resid'l Use (KWH)	10451	10405	10500
Avg. Resid'l Revs. per KWH(¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	+.6	+1.7
Fixed Charge Cov. (%)	253	246	250

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '19-'21
Revenues	-7.0%	-15.0%	2.5%
"Cash Flow"	-1.0%	-0.5%	5.0%
Earnings	-3.0%	-6.0%	8.0%
Dividends	3.0%	--	Nil
Book Value	--	-1.5%	NMF

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	1178	1053	1344	1091	4666.0
2014	1330	1117	1313	1118	4878.0
2015	1371	1140	1362	1127	5000
2016	1350	1200	1550	1300	5400
2017	1410	1270	1610	1360	5650

Cal-endar	EARNINGS PER SHARE A F Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.24	.22	.44	.24	1.14
2014	.30	.21	.31	.14	.96
2015	.21	.21	.36	.27	1.05
2016	.23	.23	.39	.30	1.15
2017	.25	.25	.41	.31	1.22

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.27	.27	.27	.27	1.08
2013	.27	.27	.27	.27	1.08
2014	.27	.27	.27	.27	1.08
2015	.27	.27	.27	.27	1.08
2016					

BUSINESS: Pepco Holdings, Inc. consists mainly of three electric utility subsidiaries: Potomac Electric Power Co., serving Washington, D.C. and adjoining areas of Maryland; Delmarva Power, which serves the peninsula area of Delaware, Maryland and Virginia; and Atlantic City Electric, serving southern New Jersey. In July 2010, Pepco sold competitive energy business (Conectiv Energy) to Calpine Corp. Electricity customers: 1.8 million; gas customers: 125,000. Electricity breakdown: residential, 40%; commercial, 41%; other, 19%. 2014 depreciation rate: 2.5%. Has approximately 5,125 employees as of 12/31/14. Chrmn., Pres. & CEO: Joseph M. Rigby. Inc.: DE. Address: 701 Ninth Street, N.W., Wash., D.C. 20068. Telephone.: 202-872-2000. Internet: www.pepcoholdings.com.

March 4th may be make or break for Pepco Holdings' acquisition by Exelon Corp. Indeed, Christopher Crane, the CEO of Exelon, said during a recent conference call with equity analysts that his company will walk away from its planned merger with Pepco if the District of Columbia Public Service Commission (DCPSC) doesn't issue a ruling on the deal by that date. The DCPSC had previously suggested that it would make a decision by March 4th only to backtrack later, saying that it was under no obligation to meet the deadline. For his part, Mr. Crane has said that, absent a March 4th ruling, Exelon will begin buying back the nearly 58 million shares that it issued to help fund the $6.8 billion deal. This which would effectively end the 20-month courtship. That said, it is possible that CEO Crane was posturing a bit, given what's been a rather lengthy – and likely exhausting – merger review.

We still believe that a deal could get done. Underpinning our confidence is a belief that the long list of proposed merger concessions is sufficient enough to allay concerns that the marriage is not in the public interest. To that point, the two utilities have already said that they'll provide affordable rates for low-income households and invest further in clean, renewable energy. Chicago-based Exelon has also agreed to relocate a portion of the post-merger utility's headquarters to the DC area.

Our Timeliness rank for Pepco shares remains suspended due to the pending merger. At the recent quotation, the stock is trading approximately 4% below Exelon's $27.25-a-share, all-cash takeover offer. That said, we still recommend that investors take profits here, given the odds – however slim – that the deal is blocked. Were that to happen, a reversion to Pepco's premerger announcement trading levels (of $19 and change per share) is possible in our view, partly reflecting the unwinding of large arbitrage-related positions. It is also worth noting that, with its lackluster earnings record, Pepco hasn't increased its dividend in more than seven years. Accordingly, income-seeking investors should look elsewhere for utility industry exposure.

Nils C. Van Liew *February 19, 2016*

(A) Based on dil. shs. Excl. nonrecur. items: '05, 47¢; '06, d1¢; '08, 46¢; '10, 62¢ '13, 69¢. Next egs. rpt. due early March. (B) Div'ds paid in early March, June, Sep., and Dec. ■ Div'd reinvest. plan. (C) Incl. def'd chgs: '14, $4.5 bill. or $17.80/sh. (D) In mill. (E) Rate allowed in MD: 9.62% ('14-Pepco), 10.0% ('09-Delmarva); DC: 9.6% ('10-Pep.); DEL: 10.0% ('06-Del.); NJ: 9.75% ('14-ACE); Earned on '14 avg. com. eq., 5.6%. Reg. Clim.: Avg. (F) Qtrly egs. may not add due to chng. in shs.

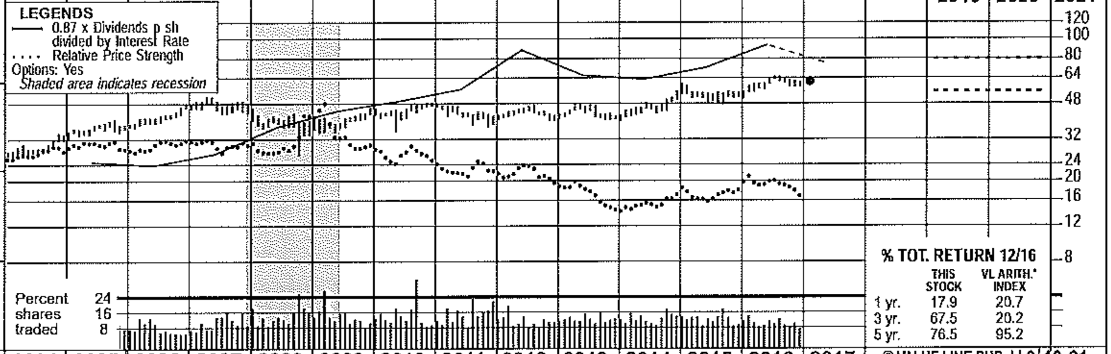
Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	20
Earnings Predictability	70

PG&E CORP. NYSE-PCG

RECENT PRICE 61.78 | P/E RATIO 16.2 (Trailing: 35.9; Median: 16.0) | RELATIVE P/E RATIO 0.82 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 2 Raised 12/9/16
SAFETY 3 Lowered 2/3/12
TECHNICAL 3 Raised 1/13/17
BETA .65 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	40.1	48.2	52.2	45.7	45.8	48.6	48.0	47.0	48.5	55.2	60.2	65.4
Low:	31.8	36.3	42.6	26.7	34.5	34.9	36.8	39.4	39.9	39.4	47.3	50.7



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+30%)	10%
Low	55	(-10%)	1%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	10	0	11	0	0	1	0	0	0
to Sell	2	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2016	2Q2016	3Q2016
to Buy	303	302	250
to Sell	194	200	260
Hld's(000)	409084	404165	405893

% TOT. RETURN 12/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	17.9	20.7
3 yr.	67.5	20.2
5 yr.	76.5	95.2

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
67.75	63.18	32.74	25.05	26.47	31.78	36.02	37.42	40.51	36.15	35.02	36.28	34.92	34.16	35.91	34.21	33.95	34.55	Revenues per sh	38.75
.80	5.66	1.14	4.80	5.71	7.12	7.76	8.02	8.44	8.37	8.22	8.08	7.32	6.33	8.13	7.29	8.55	9.60	"Cash Flow" per sh	10.75
d9.21	3.02	d2.36	2.05	2.12	2.35	2.76	2.78	3.22	3.03	2.82	2.78	2.07	1.83	3.06	2.00	2.90	3.65	Earnings per sh A	4.25
1.20	--	--	--	--	1.23	1.32	1.44	1.56	1.68	1.82	1.82	1.82	1.82	1.82	1.82	1.93	2.08	Div'd Decl'd per sh B ■ †	2.70
4.54	7.33	7.94	4.08	3.72	4.90	6.90	7.83	10.05	10.68	9.62	9.79	10.74	11.40	10.16	10.51	11.25	11.65	Cap'l Spending per sh	11.50
8.19	11.89	9.47	10.12	20.62	19.60	22.44	24.18	25.97	27.88	28.55	29.35	30.35	31.41	33.09	33.69	35.20	37.20	Book Value per sh C	43.00
387.19	363.38	381.67	416.52	418.62	368.27	348.14	353.72	361.06	370.60	395.23	412.26	430.72	456.67	475.91	492.03	507.00	515.00	Common Shs Outst'g D	530.00
--	4.8	--	9.5	13.8	15.4	14.8	16.8	12.1	13.0	15.8	15.5	20.7	23.7	15.0	26.4	20.6		Avg Ann'l P/E Ratio	15.5
--	.25	--	.54	.73	.82	.80	.89	.73	.87	1.01	.97	1.32	1.33	.79	1.33	1.10		Relative P/E Ratio	.95
4.8%	--	--	--	--	3.4%	3.2%	3.1%	4.0%	4.3%	4.1%	4.2%	4.2%	4.2%	4.0%	3.4%	3.2%		Avg Ann'l Div'd Yield	4.1%

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
12539	13237	14628	13399	13841	14956	15040	15598	17090	16833	17200	17800	Revenues ($mill)	20600
1005.0	1020.0	1198.0	1168.0	1113.0	1132.0	893.0	828.0	1450.0	988.0	1460	1910	Net Profit ($mill)	2320
35.5%	34.6%	26.2%	31.1%	33.0%	30.3%	23.9%	24.5%	19.2%	19.2%	25.0%	25.5%	Income Tax Rate	27.0%
6.7%	9.4%	9.5%	11.9%	14.4%	11.2%	17.5%	17.9%	10.0%	15.7%	11.0%	8.0%	AFUDC % to Net Profit	7.0%
51.7%	52.6%	52.2%	51.4%	49.6%	48.8%	48.7%	46.6%	48.5%	48.8%	49.5%	49.0%	Long-Term Debt Ratio	48.0%
46.8%	46.1%	46.5%	47.4%	49.3%	50.2%	50.4%	52.5%	50.7%	50.4%	49.5%	50.5%	Common Equity Ratio	51.5%
16696	18558	20163	21793	22863	24119	25956	27311	31050	32858	35925	37950	Total Capital ($mill)	44500
21785	23656	26261	28892	31449	33655	37523	41252	43941	46723	49550	52500	Net Plant ($mill)	60700
7.6%	7.4%	7.8%	6.7%	6.2%	5.9%	4.7%	4.2%	5.8%	4.1%	5.0%	6.0%	Return on Total Cap'l	6.5%
12.5%	11.6%	12.4%	11.0%	9.6%	9.2%	6.7%	5.7%	9.1%	5.9%	8.0%	10.0%	Return on Shr. Equity	10.0%
12.7%	11.8%	12.6%	11.2%	9.7%	9.2%	6.7%	5.7%	9.1%	5.9%	8.0%	10.0%	Return on Com Equity E	10.0%
6.8%	6.0%	6.8%	5.5%	3.9%	3.4%	1.0%	.2%	3.9%	.7%	2.5%	4.5%	Retained to Com Eq	4.0%
47%	50%	47%	52%	61%	63%	85%	96%	58%	88%	67%	56%	All Div'ds to Net Prof	62%

CAPITAL STRUCTURE as of 9/30/16
Total Debt $17833 mill. **Due in 5 Yrs** $4718 mill.
LT Debt $16528 mill. **LT Interest** $766 mill.
(LT interest earned: 1.8x)
Pension Assets-12/15 $13745 mill.
Oblig. $16299 mill.
Pfd Stock $252 mill. **Pfd Div'd** $14 mill.
4,534,958 shs. 4.36% to 5%, cumulative and $25 par, redeemable from $25.75 to $27.25; 5,784,825 shs. 5.00% to 6.00%, cumulative nonredeemable and $25 par.
Common Stock 505,666,694 shs. as of 10/24/16
MARKET CAP: $31 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	+.5	-.2	-.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	9.28	9.98	9.73
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	NMF	NMF	NMF
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+.3	+.6	+.7
Fixed Charge Cov. (%)	223	304	189

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	2.5%	-1.5%	2.0%
"Cash Flow"	2.0%	-3.0%	7.0%
Earnings	.5%	-5.5%	11.0%
Dividends	--	1.5%	7.0%
Book Value	7.0%	3.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	3672	3776	4175	3975	15598
2014	3891	3952	4939	4308	17090
2015	3899	4217	4550	4167	16833
2016	3974	4169	4810	4247	17200
2017	4200	4400	4800	4400	17800

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.55	.74	.36	.19	1.83
2014	.49	.57	1.71	.27	3.06
2015	.27	.83	.63	.27	2.00
2016	.22	.46	.77	1.45	2.90
2017	.85	.75	1.30	.75	3.65

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.455	.455	.455	.455	1.82
2014	.455	.455	.455	.455	1.82
2015	.455	.455	.455	.455	1.82
2016	.455	.455	.49	.49	1.89
2017	.49				

BUSINESS: PG&E Corporation is a holding company for Pacific Gas and Electric Company and nonutility subsidiaries. Supplies electricity and gas to most of northern and central California. Has 5.3 million electric and 4.4 million gas customers. Electric revenue breakdown: residential, 38%; commercial, 40%; industrial, 12%; agricultural, 9%; other, 1%. Generating sources: nuclear, 23%; gas, 9%; hydro, 5%; purchased, 63%. Fuel costs: 34% of revenues. '15 reported depreciation rate (utility): 3.8%. Has 23,000 employees. Chairman, President & Chief Executive Officer: Anthony F. Earley, Jr. President & CEO (effective 3/1/17): Geisha J. Williams. Inc.: California. Address: 77 Beale Street, P.O. Box 770000, San Francisco, CA 94177. Tel.: 415-973-1000. Internet: www.pgecorp.com.

PG&E is awaiting an order on its general rate case. The utility reached a contested settlement calling for rate increases of $88 million in 2017, $444 million in 2018, and $361 million in 2019. A hike of $361 million is recommended for 2020, but this is one of the contested issues. An administrative law judge will put forth a proposed decision before the California commission issues its order, which is expected in February. The ruling will be retroactive to the start of the new year.

Earnings should return to a normal level beginning in 2017. Ever since a gas pipeline exploded in San Bruno, California in September of 2010, causing fatalities, injuries, and extensive property damage, the company's income (as we present it) has included charges for unrecovered pipeline safety enhancements, revenue refunds, and related legal costs. (We excluded fines because these are not operational in nature.) PG&E has funded much of this through equity issuances, which is why the share count has risen so sharply since 2010. The company issued an estimated $800 million of common equity last year, and expects to issue $400 million-$600 million in 2017. PG&E has issued 2017 share-earnings guidance of $3.51-$3.80 a share based on GAAP. Our previous forecast of $3.90 was too optimistic, so we have lowered it by $0.25 a share.

A cost-of-capital filing is possible this year. Note that California regulation looks at the cost of capital in proceedings that are separate from general rate cases. In recent years, utilities in California have reached settlements regarding the cost of capital. They will try collectively for an agreement this year; if one isn't reached, they will file cost-of-capital cases in April, with rulings to take effect in 2018.

Now that dividend growth has resumed, increases should come at a healthy pace. Understandably, the board did not raise the disbursement for five years after the San Bruno accident. In 2016, the directors declared a 7.7% boost, and we look for another solid hike this year.

This timely stock has a dividend yield and 3- to 5-year total return potential that are close to the averages for the utility industry.

Paul E. Debbas, CFA *January 27, 2017*

(A) Diluted EPS. Excl. nonrec. gains (losses): '04, $6.95; '09, 18¢; '11, (68¢); '12, (15¢); '15, (21¢); '16, (5¢); gain from disc. ops.: '08, 41¢. '13 EPS don't add due to rounding, '14 due to change in shs. Next earnings report due mid-Feb. (B) Div'ds historically paid in mid-Jan., Apr., July, and Oct. ■ Div'd reinvest. plan avail. † Shareholder investment plan avail. (C) Incl. intang. In '15: $14.29/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. in '15: 10.4%; earned on avg. com. eq., '15: 6.0%. Regulatory Climate: Average.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistance	35
Earnings Predictability	50

PINNACLE WEST NYSE-PNW

RECENT PRICE 78.00 | P/E RATIO 18.7 (Trailing: 20.3 Median: 15.0) | RELATIVE P/E RATIO 0.94 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 3 Lowered 10/14/16
SAFETY 1 Raised 5/3/13
TECHNICAL 3 Raised 1/27/17
BETA .70 (1.00 = Market)

High:	46.7	51.0	51.7	42.9	38.0	42.7	48.9	54.7	61.9	71.1	73.3	82.8
Low:	39.8	38.3	36.8	26.3	22.3	32.3	37.3	45.9	51.5	51.2	56.0	62.5

Target Price Range 2019 | 2020 | 2021

2019-21 PROJECTIONS

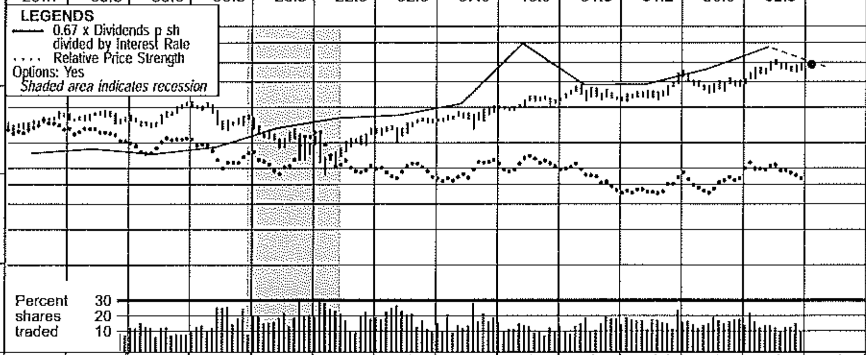
	Price	Gain	Ann'l Total Return
High	80	(+5%)	4%
Low	65	(-15%)	Nil

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	4	0	0	0	0	12	2
to Sell	4	0	0	0	0	0	1	0	0

Institutional Decisions

	1Q2016	2Q2016	3Q2016
to Buy	221	206	182
to Sell	182	189	192
Hld's(000)	92857	91259	90564



% TOT. RETURN 12/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	25.3	20.7
3 yr.	65.2	20.2
5 yr.	96.5	95.2

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
43.50	53.66	28.90	30.87	31.59	30.16	34.03	35.07	33.37	32.50	30.01	29.67	30.09	31.35	31.58	31.50	*31.40*	*33.05*	Revenues per sh	*37.50*
7.99	8.72	7.01	7.33	6.93	5.76	9.70	9.29	8.13	8.08	6.85	7.52	7.92	8.15	8.09	9.09	*9.25*	*9.90*	"Cash Flow" per sh	*11.50*
3.35	3.68	2.53	2.52	2.58	2.24	3.17	2.96	2.12	2.26	3.08	2.99	3.50	3.66	3.58	3.92	*3.90*	*4.30*	Earnings per sh A	*4.75*
1.43	1.53	1.63	1.73	1.83	1.93	2.03	2.10	2.10	2.10	2.10	2.10	2.67	2.23	2.33	2.44	2.56	*2.68*	Div'd Decl'd per sh B ■	*3.10*
7.76	12.27	9.81	7.60	5.86	6.39	7.59	9.37	9.46	7.64	7.03	8.26	8.24	9.36	8.38	9.84	*11.50*	*12.45*	Cap'l Spending per sh	*10.25*
28.09	29.46	29.44	31.00	32.14	34.57	34.48	35.15	34.16	32.69	33.86	34.98	36.20	38.07	39.50	41.30	*42.60*	*44.20*	Book Value per sh C	*49.00*
84.83	84.83	91.26	91.29	91.79	99.08	99.96	100.49	100.89	101.43	108.77	109.25	109.74	110.18	110.57	110.98	*111.50*	*112.00*	Common Shs Outst'g D	*113.50*
11.3	12.0	14.4	14.0	15.8	19.2	13.7	14.9	16.1	13.7	12.6	14.6	14.3	15.3	15.9	16.0	*19.0*		Avg Ann'l P/E Ratio	*15.5*
.73	.61	.79	.80	.83	1.02	.74	.79	.97	.91	.80	.92	.91	.86	.84	.81	*1.00*		Relative P/E Ratio	*.95*
3.8%	3.5%	4.5%	4.9%	4.5%	4.5%	4.7%	4.8%	6.2%	6.8%	5.4%	4.8%	5.3%	4.0%	4.1%	3.9%	3.5%		Avg Ann'l Div'd Yield	*4.2%*

CAPITAL STRUCTURE as of 9/30/16
Total Debt $4279.5 mill. Due in 5 Yrs $1531.9 mill.
LT Debt $4145.4 mill. LT Interest $192.2 mill.
Incl. $13.4 mill. Palo Verde sele leaseback lessor notes.
(LT interest earned: 4.8x)
Leases, Uncapitalized Annual rentals $18.0 mill.
Pension Assets-12/15 $2542.8 mill. Oblig. $3033.8 mill.
Pfd Stock None
Common Stock 111,306,107 shs. as of 10/28/16
MARKET CAP: $8.7 billion (Large Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
3401.7	3523.6	3367.1	3297.1	3263.6	3241.4	3301.8	3454.6	3491.6	3495.4	*3500*	*3700*	Revenues ($mill)	*4250*
317.1	298.8	213.6	229.2	330.4	328.2	387.4	406.1	397.6	437.3	*435*	*485*	Net Profit ($mill)	*550*
33.0%	33.6%	23.4%	36.9%	31.9%	34.0%	36.2%	34.4%	34.2%	34.3%	*34.5%*	*34.5%*	Income Tax Rate	*34.5%*
11.1%	14.8%	17.5%	11.2%	11.7%	12.8%	9.7%	10.0%	11.6%	11.8%	*11.0%*	*11.0%*	AFUDC % to Net Profit	*8.0%*
48.4%	47.0%	46.8%	50.4%	45.3%	44.1%	44.6%	40.0%	41.0%	43.0%	*46.0%*	*46.5%*	Long-Term Debt Ratio	*45.0%*
51.6%	53.0%	53.2%	49.6%	54.7%	55.9%	55.4%	60.0%	59.0%	57.0%	*54.0%*	*53.5%*	Common Equity Ratio	*55.0%*
6678.7	6658.7	6477.6	6686.6	6729.1	6840.9	7171.9	6990.9	7398.7	8046.3	*8790*	*9240*	Total Capital ($mill)	*10150*
7881.9	8436.4	8916.7	9257.8	9578.8	9962.3	10396	10889	11194	11809	*12500*	*13275*	Net Plant ($mill)	*14625*
6.2%	5.9%	4.7%	4.8%	6.5%	6.4%	6.8%	7.1%	6.4%	6.4%	*6.0%*	*6.5%*	Return on Total Cap'l	*6.5%*
9.2%	8.5%	6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	9.5%	*9.0%*	*10.0%*	Return on Shr. Equity	*10.0%*
9.2%	8.5%	6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	9.5%	*9.0%*	*10.0%*	Return on Com Equity E	*10.0%*
3.4%	2.5%	.3%	.7%	3.1%	2.8%	4.1%	4.1%	3.5%	3.9%	*3.0%*	*3.5%*	Retained to Com Eq	*3.5%*
63%	70%	96%	89%	66%	68%	58%	58%	62%	59%	*65%*	*62%*	All Div'ds to Net Prof	*64%*

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	-.2	-1.8	+1.3
Avg. Indust. Use (MWH)	644	659	658
Avg. Indust. Revs. per KWH (¢)	8.21	8.26	8.17
Capacity at Peak (Mw)	8398	9259	9250
Peak Load, Summer (Mw)	6927	7007	7031
Annual Load Factor (%)	50.0	48.6	48.3
% Change Customers (yr-end)	+1.4	+1.2	+1.3
Fixed Charge Cov. (%)	419	404	438

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	--	-.5%	*3.0%*
"Cash Flow"	2.5%	2.0%	*5.5%*
Earnings	4.5%	8.5%	*4.0%*
Dividends	2.5%	2.0%	*5.0%*
Book Value	2.0%	3.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	686.6	915.8	1152.4	699.8	3454.6
2014	686.2	906.3	1172.7	726.4	3491.6
2015	671.2	890.7	1199.1	734.4	3495.4
2016	677.2	915.4	1166.9	*740.5*	*3500*
2017	*700*	*950*	*1275*	*775*	*3700*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.22	1.18	2.04	.22	3.66
2014	.14	1.19	2.20	.05	3.58
2015	.14	1.10	2.30	.37	3.92
2016	.04	1.08	2.35	*.43*	*3.90*
2017	*.20*	*1.20*	*2.50*	*.40*	*4.30*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.545	.545	.545	.567	2.20
2014	.568	.568	.568	.595	2.30
2015	.595	.595	.595	.625	2.41
2016	.625	.625	.625	.655	2.53
2017					

BUSINESS: Pinnacle West Capital Corporation is a holding company for Arizona Public Service Company (APS), which supplies electricity to 1.2 million customers in most of Arizona, except about half of the Phoenix metro area, the Tucson metro area, and Mohave County in northwestern Arizona. Discontinued SunCor real estate subsidiary in '10. Electric revenue breakdown: residential, 49%; commercial, 39%; industrial, 5%; other, 7%. Generating sources: coal, 31%; nuclear, 27%; gas & other, 20%; purchased, 22%. Fuel costs: 32% of revenues. '15 reported deprec. rate: 2.7%. Has 6,400 employees. Chairman, President & CEO: Donald E. Brandt. Inc.: AZ. Address: 400 North Fifth St., P.O. Box 53999, Phoenix, AZ 85072-3999. Tel.: 602-250-1000. Internet: www.pinnaclewest.com.

The Arizona Corporation Commission (ACC) is holding hearings on the rate case filed by Pinnacle West's utility subsidiary. Arizona Public Service is seeking a hike of $165.9 million (5.7%), based on a 10.5% return on a 55.8% common-equity ratio. The ACC's staff is recommending no change in rates and a 9.35% ROE, while an intervenor group is proposing a $24 million *decrease* and a 9.42% ROE. However, the most significant aspect of this case is rate design, not the revenue requirement. Currently, the 96% of APS' customers that do not have rooftop solar are subsidizing the 4% that do. So, the utility proposes raising the fixed portion of residential customers' bills, lowering the variable component, and adding a third component that is a demand charge based on the highest demand average over a one-hour period during the on-peak time each month. Even this would not eliminate subsidization, just reduce it. APS also wants to increase its recovery of lost revenues stemming from energy efficiency and defer for future recovery costs associated with two major construction projects. New tariffs should take effect in midyear.

The utility has begun construction of two large projects. APS is adding pollution control equipment to two coal-fired units at the Four Corners station. This is expected to be in service in the spring of 2018 at a cost of $400 million. The company is also building five gas-fired units that will replace older plants for a net increase in generating capacity of 220 megawatts. This is expected to be completed by the spring of 2019 at a cost of $500 million.

We forecast a 10% earnings increase this year. In 2016, the cost of major plant overhauls hurt profits in the first half, and a milder-than-normal summer affected income in the third period. Thus, the comparison with the 2016 tally should be easy.

As we had expected, the board of directors raised the quarterly dividend by $0.03 a share (4.8%) in the fourth quarter of 2016. Pinnacle West's goal for annual dividend growth is 5%.

This stock is priced expensively. The dividend yield doesn't stand out among utilities. With the recent price near the upper end of our 3- to 5-year Target Price Range, total return potential is low.

Paul E. Debbas, CFA *January 27, 2017*

(A) Diluted EPS. Excl. nonrec. losses: '02, 77¢; '09, $1.45; excl. gains (losses) from disc. ops.: '00, 22¢; '05, (36¢); '06, 10¢; '08, 28¢; '09, (13¢); '10, 18¢; '11, 10¢; '12, (5¢). '15 EPS don't add due to rounding. Next earnings report due late Feb. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. There were 5 declarations in '12. ■ Div'd reinvest. plan avail. (C) Incl. deferred chgs. In '15: $13.77/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in '12: 10%; earned on avg. com. eq., '15: 9.8%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	90

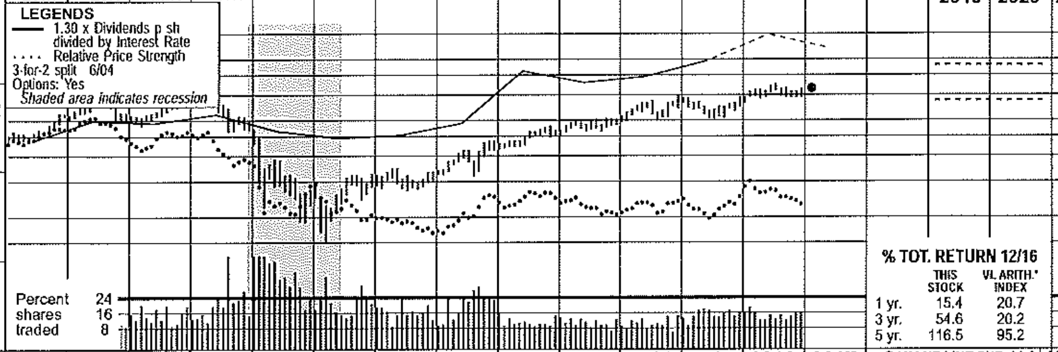
PNM RESOURCES NYSE-PNM

RECENT PRICE 34.50 | P/E RATIO 19.9 (Trailing: 22.4 Median: 17.0) | RELATIVE P/E RATIO 1.01 | DIV'D YLD 2.8% | VALUE LINE

TIMELINESS 3 Raised 1/6/17
SAFETY 3 Lowered 5/9/08
TECHNICAL 4 Lowered 1/20/17
BETA .75 (1.00 = Market)

High:	30.5	32.1	34.3	21.7	13.1	14.0	19.2	22.5	24.5	31.6	31.2	36.2
Low:	23.8	22.5	21.0	7.6	5.9	10.8	12.8	17.3	20.1	23.5	24.4	29.2

Target Price Range
2019 | 2020 | 2021



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+30%)	9%
Low	30	(-15%)	Nil

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	7	0	8	0	0	0	0	0	0
to Sell	6	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2016	2Q2016	3Q2016
to Buy	129	119	98
to Sell	97	108	129
Hld's(000)	74855	75946	75779

% TOT. RETURN 12/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	15.4	20.7
3 yr.	54.6	20.2
5 yr.	116.5	95.2

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
27.46	40.09	19.92	24.11	26.54	30.19	32.25	24.92	22.65	19.01	19.31	21.35	16.85	17.42	18.03	18.07	*17.40*	*19.40*	Revenues per sh	*20.30*
3.16	4.31	2.83	3.05	3.14	3.56	3.57	2.54	1.76	2.32	2.67	3.18	3.38	3.51	3.62	3.98	*3.85*	*4.10*	"Cash Flow" per sh	*4.70*
1.55	2.61	1.07	1.15	1.43	1.56	1.72	.76	.11	.58	.87	1.08	1.31	1.41	1.45	1.64	*1.60*	*1.85*	Earnings per sh A	*2.35*
.53	.53	.57	.61	.63	.79	.86	.91	.61	.50	.50	.50	.58	.68	.76	.80	*.88*	*.97*	Div'd Decl'd per sh B ■†	*1.30*
2.50	4.51	4.09	2.78	2.25	3.07	4.04	5.94	3.99	3.32	3.25	4.10	3.88	4.37	5.78	7.01	*5.60*	*5.65*	Cap'l Spending per sh	*5.50*
15.76	17.25	16.60	17.84	18.19	18.70	22.09	22.03	18.89	18.90	17.60	19.62	20.05	20.87	22.39	20.78	*22.70*	*23.60*	Book Value per sh C	*25.50*
58.68	58.68	58.68	60.39	60.46	68.79	76.65	76.81	86.53	86.67	86.67	79.65	79.65	79.65	79.65	79.65	*80.00*	*80.00*	Common Shs Outst'g D	*80.00*
8.5	7.3	15.1	14.7	15.0	17.4	15.6	35.6	NMF	18.1	14.0	14.5	15.0	16.1	18.7	16.8	*20.5*		Avg Ann'l P/E Ratio	*16.0*
.55	.37	.82	.84	.79	.93	.84	1.89	NMF	1.21	.89	.91	.95	.90	.98	.85	*1.08*		Relative P/E Ratio	*1.00*
4.1%	2.8%	3.5%	3.6%	2.9%	2.9%	3.2%	3.4%	4.9%	4.8%	4.1%	3.2%	3.0%	3.0%	2.8%	2.9%	*2.7%*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 9/30/16
Total Debt $2664.2 mill. Due in 5 Yrs $1054 mill.
LT Debt $2207.0 mill. LT Interest $110 mill.
(LT interest earned: 2.4x)
Pension Assets-12/15 $620.0 mill.
Oblig. $662.1 mill.

Pfd Stock $11.5 mill. Pfd Div'd $.5 mill.
115,293 shs. 4.58%, $100 par w/o mandatory redemption. Sinking fund began 2/1/84.

Common Stock 79,653,624 shs.
as of 10/21/16
MARKET CAP: $2.7 billion (Mid Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
2471.7	1914.0	1959.5	1647.7	1673.5	1700.6	1342.4	1387.9	1435.9	1439.1	*1390*	*1550*	Revenues ($mill)	*1625*
122.1	59.9	8.1	53.5	80.0	96.6	105.6	113.5	116.3	131.5	*135*	*150*	Net Profit ($mill)	*190*
24.7%	5.1%	40.4%	30.4%	32.6%	38.8%	31.4%	31.6%	34.8%	34.5%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
4.1%	--	--	6.4%	7.1%	8.8%	7.2%	1.3%	1.3%	1.5%	*2.5%*	*3.0%*	AFUDC % to Net Profit	*8.0%*
50.9%	42.0%	45.6%	48.7%	50.4%	51.5%	50.9%	50.0%	47.8%	54.1%	*53.0%*	*53.5%*	Long-Term Debt Ratio	*52.5%*
48.8%	57.6%	54.0%	51.0%	49.2%	48.1%	48.7%	49.7%	51.9%	45.5%	*46.0%*	*45.5%*	Common Equity Ratio	*46.5%*
3470.7	2935.8	3025.4	3214.9	3100.3	3245.6	3277.9	3344.0	3437.1	3633.3	*3845*	*4025*	Total Capital ($mill)	*4385*
3761.9	2935.4	3192.0	3332.4	3444.4	3627.1	3746.5	3933.9	4270.0	4535.4	*4655*	*4800*	Net Plant ($mill)	*5270*
4.9%	3.4%	1.9%	3.1%	4.2%	4.5%	5.1%	5.2%	5.1%	5.2%	*5.0%*	*5.5%*	Return on Total Cap'l	*6.0%*
7.2%	3.5%	.5%	3.2%	5.2%	6.1%	6.6%	6.8%	6.5%	7.9%	*7.5%*	*8.0%*	Return on Shr. Equity	*9.5%*
7.2%	3.5%	.5%	3.2%	5.2%	6.1%	6.6%	6.8%	6.5%	7.9%	*7.5%*	*8.0%*	Return on Com Equity E	*9.5%*
3.7%	NMF	NMF	.4%	2.2%	3.3%	3.8%	3.7%	3.2%	4.1%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
49%	117%	NMF	86%	58%	47%	43%	45%	51%	49%	*51%*	*52%*	All Div'ds to Net Prof	*55%*

ELECTRIC OPERATING STATISTICS F

	2013	2014	2015
% Change Retail Sales (KWH)	-2.9	-2.1	+2.1
Avg. Indust. Use (MWH)	N/A	N/A	N/A
Avg. Indust. Revs. per KWH (¢)	N/A	N/A	N/A
Capacity at Peak (Mw)	2572	2707	2787
Peak Load, Summer (Mw)	2008	1948	1889
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	+.7	+.6	+.9
Fixed Charge Cov. (%)	241	250	N/A

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	-4.0%	-2.5%	*1.5%*
"Cash Flow"	1.5%	10.5%	*5.0%*
Earnings	1.0%	23.5%	*9.0%*
Dividends	1.0%	7.0%	*10.0%*
Book Value	1.5%	3.0%	*3.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	317.7	347.6	399.7	322.9	1387.9
2014	328.9	346.2	413.9	346.9	1435.9
2015	332.9	352.9	417.4	335.9	1439.1
2016	311.0	315.4	400.4	*363.2*	*1390*
2017	*355*	*370*	*455*	*370*	*1550*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.18	.38	.64	.21	1.41
2014	.16	.36	.69	.24	1.45
2015	.21	.44	.76	.23	1.64
2016	.13	.40	.78	*.29*	*1.60*
2017	*.24*	*.42*	*.81*	*.38*	*1.85*

Calendar	QUARTERLY DIVIDENDS PAID B ■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.145	.165	.165	.165	.64
2014	.185	.185	.185	.185	.74
2015	.20	.20	.20	.20	.80
2016	.22	.22	.22	.22	.88
2017	.2425				

BUSINESS: PNM Resources is a holding company with two regulated electric utilities. Its Public Service of New Mexico unit (PNM) provides power generation, tranmission, and distribution services across north central New Mexico, including the cities of Albuquerque and Santa Fe. Texas-New Mexico Power Company (TNMP) transmits and distributes power throughout New Mexico. Electric rev. breakdown '15: residential, 30%; commercial, 32%; industrial, 19%; other, 19%. Fuels: coal, 57%; nuclear, 30%; gas/oil, 12%; solar, 1%. Fuel costs: 49% of revenues. '15 depreciation rate: 3.3%. Has 1,881 employees. Chairman, President & CEO: Patricia K. Collawn. Inc.: NM. Address: 414 Silver Ave. SW, Albuquerque, NM. 87102. Tel.: 505-241-2700. Internet: www.pnmresources.com.

PNM Resources is seeking another rate hike. Indeed, in early December, the company's regulated power unit (PSNM) filed a request to raise rates within its New Mexico service area by a total of $99.2 million. The petition is based on a (2018) future test period, seeks a 10.125% return on equity, and covers, among other things, costs associated with transitioning to cleaner power sources and reducing air pollution in the Four Corners area. It comes just months after a contentious $65.7 million increase went into effect. That approval was well below PNM's initial ($123.5 million) request and is still being contested in the courts.

The utility is hoping to soften the blow. While the proposed $99.2 million rate hike translates into a large increase of around 13% for residential customers, Public Service of New Mexico is planning a gentle, two-year phase in. It has also said that it remains committed to the Good Neighbor Fund, which has been set up to help low-income customers with their bills. Still, if past is prelude, PNM likely faces a tough go of it in winning full approval.

PNM recently reaffirmed its target of 7%-8% annual earnings growth over a five-year period (2015-2019). Key to reaching that goal will be the utility's ability to both earn authorized returns on its regulated businesses and minimize regulatory lag. A better regional economy should help, as well. With that in mind, certain leading indicators of residential and commercial growth recently turned positive. What's more, Facebook's recent decision to build a new data center in Los Lunas (just South of Albuquerque) may spur other companies to consider the Land of Enchantment for major projects.

Shares of PNM Resources are an Average selection for relative year-ahead price performance (Timeliness: 3). At the stock's recent quotation, long-term total return potential doesn't stand out, either. While we look for the company to maintain a competitive dividend going forward, we think higher interest rates and a reset in risk spreads will limit upside in income vehicles, including utility stocks. PNM, meantime, faces unique challenges, including above-average regulatory risk.

Nils C. Van Liew *January 27, 2017*

(A) EPS dil. Excl. n/r gains (losses): '00, 21¢; '01, (15¢); '03, 67¢; '05, (56¢); '08, ($3.77); '10, ($1.36); '11, 88¢. '13, (16); Excl. disc. ops.: '08, 42¢; '09, 78¢. Egs. may not sum due to rounding. Next egs. rpt. due early February. (B) Div'ds hist. pd. in Feb., May, Aug., Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. '15: $3.49/sh. (D) In mill., adjust. for split. (E) Rate base: net orig. cost. ROE allowed in '11: 10.0%; earned on avg. com. eq., '13: 10.0%. Reg. Climate: Below Avg. (F) Excl. First Choice.

Company's Financial Strength	B
Stock's Price Stability	90
Price Growth Persistence	65
Earnings Predictability	65

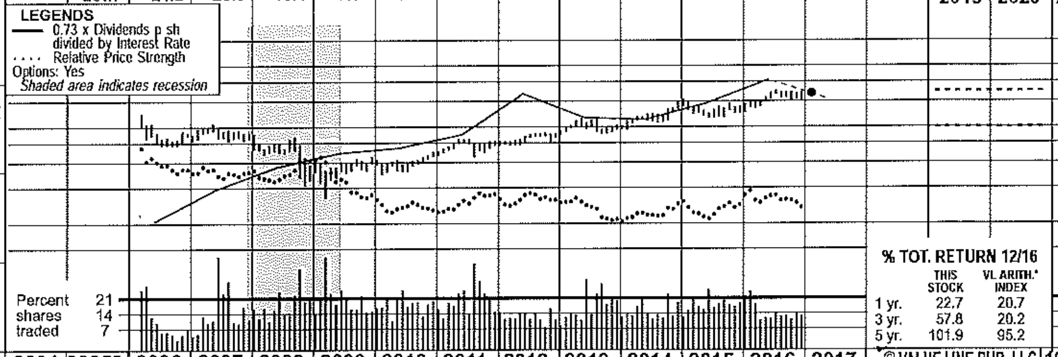
PORTLAND GENERAL NYSE-POR

RECENT PRICE 43.95 | P/E RATIO 20.0 (Trailing: 21.4 Median: 15.0) | RELATIVE P/E RATIO 1.01 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS 3 Lowered 8/19/16
SAFETY 2 Raised 5/4/12
TECHNICAL 3 Lowered 12/30/16
BETA .70 (1.00 = Market)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	35.0	31.3	27.7	21.4	22.7	26.0	28.1	33.3	40.3	41.0	45.2
Low:	24.2	25.5	15.4	13.5	17.5	21.3	24.3	27.4	29.0	33.0	35.3

Target Price Range 2019 | 2020 | 2021



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(Nil)	4%
Low	30	(-30%)	-5%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	10	0	0	0	0	0	0
to Sell	0	0	1	0	0	0	0	0	0

Institutional Decisions

	1Q2016	2Q2016	3Q2016
to Buy	139	119	96
to Sell	116	133	146
Hld's(000)	87246	86154	84749

% TOT. RETURN 12/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	22.7	20.7
3 yr.	57.8	20.2
5 yr.	101.9	95.2

2000	2001	2002	2003	2004	2005F	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
--	--	--	--	--	23.14	24.32	27.87	27.89	23.99	23.67	24.06	23.89	23.18	24.29	21.38	21.35	22.40	Revenues per sh	24.50
--	--	--	--	--	4.75	4.64	5.21	4.71	4.07	4.82	4.96	5.15	4.93	6.08	5.37	5.70	6.10	"Cash Flow" per sh	7.25
--	--	--	--	--	1.02	1.14	2.33	1.39	1.31	1.66	1.95	1.87	1.77	2.18	2.04	2.10	2.30	Earnings per sh A	2.50
--	--	--	--	--	--	.68	.93	.97	1.01	1.04	1.06	1.08	1.10	1.12	1.18	1.26	1.34	Div'd Decl'd per sh B ■ †	1.60
--	--	--	--	--	4.08	5.94	7.28	6.12	9.25	5.97	3.98	4.01	8.40	12.87	6.73	7.05	6.65	Cap'l Spending per sh	3.50
--	--	--	--	--	19.15	19.58	21.05	21.64	20.50	21.14	22.07	22.87	23.30	24.43	25.43	26.20	27.10	Book Value per sh C	30.00
--	--	--	--	--	62.50	62.50	62.53	62.58	75.21	75.32	75.36	75.56	78.09	78.23	88.79	89.00	89.20	Common Shs Outst'g D	89.80
--	--	--	--	--	--	23.4	11.9	16.3	14.4	12.0	12.4	14.0	16.9	15.3	17.7	19.6		Avg Ann'l P/E Ratio	15.0
--	--	--	--	--	--	1.26	.63	.98	.96	.76	.78	.89	.95	.81	.89	1.05		Relative P/E Ratio	.95
--	--	--	--	--	--	2.5%	3.3%	4.3%	5.4%	5.2%	4.4%	4.1%	3.7%	3.3%	3.3%	3.1%		Avg Ann'l Div'd Yield	4.2%

CAPITAL STRUCTURE as of 9/30/16
Total Debt $2325 mill. Due in 5 Yrs $698 mill.
LT Debt $2325 mill. LT Interest $112 mill.
(LT interest earned: 2.6x)
Leases, Uncapitalized Annual rentals $10 mill.

Pension Assets-12/15 $550 mill. Oblig. $758 mill.

Pfd Stock None

Common Stock 88,926,854 shs. as of 10/17/16

MARKET CAP: $3.9 billion (Mid Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
1520.0	1743.0	1745.0	1804.0	1783.0	1813.0	1805.0	1810.0	1900.0	1898.0	1900	2000	Revenues ($mill)	2200
71.0	145.0	87.0	95.0	125.0	147.0	141.0	137.0	175.0	172.0	185	205	Net Profit ($mill)	235
33.6%	33.8%	28.7%	28.8%	30.5%	26.3%	31.4%	23.2%	26.0%	20.7%	21.5%	21.5%	Income Tax Rate	21.5%
33.8%	17.9%	17.2%	31.6%	17.6%	5.4%	7.1%	14.6%	33.7%	19.8%	14.0%	7.0%	AFUDC % to Net Profit	3.0%
43.4%	49.9%	46.2%	50.3%	53.0%	49.6%	47.1%	51.3%	52.7%	47.8%	48.0%	50.5%	Long-Term Debt Ratio	50.5%
56.6%	50.1%	53.8%	49.7%	47.0%	50.4%	52.9%	48.7%	47.3%	52.2%	52.0%	49.5%	Common Equity Ratio	49.5%
2161.0	2629.0	2518.0	3100.0	3390.0	3298.0	3264.0	3735.0	4037.0	4329.0	4485	4895	Total Capital ($mill)	5425
2718.0	3066.0	3301.0	3858.0	4133.0	4285.0	4392.0	4880.0	5679.0	6012.0	6320	6580	Net Plant ($mill)	6475
4.7%	6.9%	5.0%	4.5%	5.4%	6.2%	5.9%	5.1%	5.8%	5.4%	5.5%	5.5%	Return on Total Cap'l	5.5%
5.8%	11.0%	6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	9.2%	7.6%	8.0%	8.5%	Return on Shr. Equity	8.5%
5.8%	11.0%	6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	9.2%	7.6%	8.0%	8.5%	Return on Com Equity E	8.5%
3.5%	6.6%	2.0%	1.5%	3.0%	4.1%	3.5%	2.9%	4.6%	3.3%	3.0%	3.5%	Retained to Com Eq	3.5%
39%	40%	69%	76%	62%	54%	57%	61%	50%	56%	60%	58%	All Div'ds to Net Prof	62%

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	+1.2	-.8	+.6
Avg. Indust. Use (MWH)	16258	16577	17827
Avg. Indust. Revs. per KWH (¢)	4.84	5.13	5.01
Capacity at Peak (Mw)	4380	4910	4609
Peak Load, Winter (Mw)	3869	3866	3255
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.9	+.7	+1.2
Fixed Charge Cov. (%)	239	248	243

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	--	-2.0%	1.0%
"Cash Flow"	1.5%	4.0%	5.0%
Earnings	7.0%	6.5%	4.0%
Dividends	--	2.5%	6.0%
Book Value	2.5%	3.0%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	473.0	403.0	435.0	499.0	1810.0
2014	493.0	423.0	484.0	500.0	1900.0
2015	473.0	450.0	476.0	499.0	1898.0
2016	487.0	428.0	484.0	501	1900
2017	525	445	505	525	2000

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.65	.13	.40	.59	1.77
2014	.73	.43	.47	.55	2.18
2015	.62	.44	.40	.57	2.04
2016	.68	.42	.38	.62	2.10
2017	.75	.45	.45	.65	2.30

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.27	.27	.275	.275	1.09
2014	.275	.275	.28	.28	1.11
2015	.28	.28	.30	.30	1.16
2016	.30	.30	.32	.32	1.24
2017	.32				

BUSINESS: Portland General Electric Company (PGE) provides electricity to 863,000 customers in 52 cities in a 4,000-square-mile area of Oregon, including Portland and Selem. The company is in the process of decommissioning the Trojan nuclear plant, which it closed in 1993. Electric revenue breakdown: residential, 47%; commercial, 35%; industrial, 12%; other, 6%. Generating sources: gas, 23%; coal, 19%; wind, 8%; hydro, 7%; purchased, 43%. Fuel costs: 35% of revenues. '15 reported depreciation rate: 3.6%. Has 2,600 employees. Chairman: Jack E. Davis. President and Chief Executive Officer: James J. Piro. Incorporated: Oregon. Address: 121 S.W. Salmon Street, Portland, Oregon 97204. Telephone: 503-464-8000. Internet: www.portlandgeneral.com.

Portland General Electric's earnings should advance in 2017. The company is benefiting from an $85 million rate increase that took effect in late July last year when the Carty gas-fired generating plant began operating. In addition, we assume normal weather patterns after unfavorable weather hurt the bottom line in 2016. The service area's solid economy is another positive factor. We have trimmed our 2017 share-profit estimate by a nickel, however, because interest expense will probably wind up higher than we had estimated. PGE will probably provide 2017 earnings guidance with its next earnings release in mid-February.

The company is involved in litigation about the Carty plant. Due to construction problems, in December of 2015 PGE declared the original contractor (now in bankruptcy protection) in default of the agreement and took over management of the project. The utility is trying to collect a performance bond of $145.6 million plus additional damages, but the insurers have denied liability. Resolving this matter might well take two to four years. Only $514 million of the facility's cost (estimated at $640 million-$660 million) is in the rate base. Because the excess costs are not being recovered, this hurts annual earnings by $0.05 a share. Litigation costs are also affecting the company. These amounted to $3 million in the third quarter of 2016, and probably just as much in the fourth period, but aren't expected to be as high this year.

The utility might file a general rate case this year. PGE is evaluating the need for rate relief. It would have to put forth an application in February in order to have new tariffs take effect at the start of 2018. This is the typical timing for regulatory proceedings.

This stock is priced expensively. Its dividend yield is below the mean for electric utilities. What's more, the recent quotation is near the upper end of our 3- to 5-year Target Price Range. We think the high valuation reflects takeover speculation, but we advise against buying the equity in the hope of a buyout offer. Investors should note that a proposed acquisition of PGE was rejected by the Oregon regulators in 2005.

Paul E. Debbas, CFA *January 27, 2017*

(A) Diluted EPS. Excl. nonrecurring loss: '13, 42¢. '15 earnings don't add due to rounding. Next earnings report due mid-Feb. (B) Dividends paid mid-Jan., Apr., July, and Oct. ■ Dividend reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '15: $5.90/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '16: 9.6%; earned on avg. com. eq., '15: 8.3%. Regulatory Climate: Averege. (F) '05 per-share data are pro forma, based on shares outstanding when stock began trading in '06.

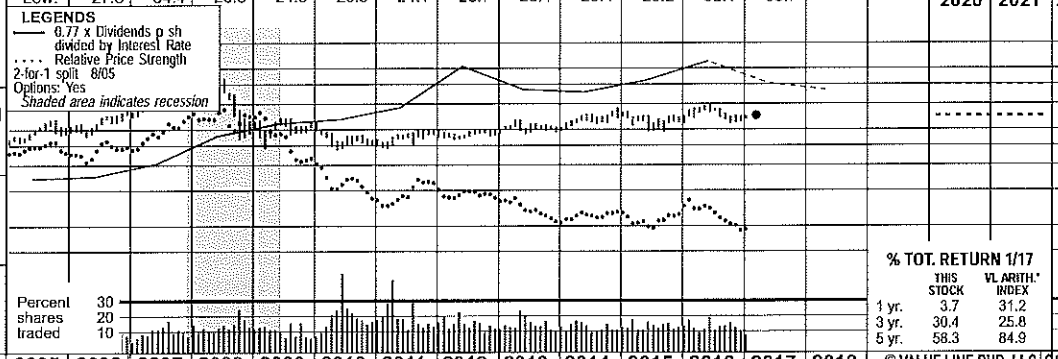
Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	70

PPL CORPORATION NYSE-PPL

RECENT PRICE 35.24 | P/E RATIO 14.8 (Trailing: 12.6 / Median: 14.0) | RELATIVE P/E RATIO 0.76 | DIV'D YLD 4.5% | VALUE LINE

TIMELINESS — Suspended 5/22/15
SAFETY 2 Raised 8/21/15
TECHNICAL — Suspended 5/22/15
BETA .70 (1.00 = Market)

High:	37.3	54.6	55.2	34.4	33.1	30.3	30.2	33.6	38.1	36.7	39.9	35.6
Low:	27.8	34.4	26.8	24.3	23.8	24.1	26.7	28.4	29.4	29.2	32.1	33.7



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+40%)	13%
Low	35	(Nil)	5%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	2	0	0	0	0	0	0
to Sell	0	0	3	2	0	0	0	0	0

Institutional Decisions

	1Q2016	2Q2016	3Q2016
to Buy	363	384	339
to Sell	289	283	340
Hld's(000)	493895	475747	471928

% TOT. RETURN 1/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	3.7	31.2
3 yr.	30.4	25.8
5 yr.	58.3	84.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
19.53	16.38	15.75	15.37	16.36	17.92	17.41	21.47	20.03	17.63	22.02	21.11	18.82	17.27	11.38	11.06	*9.85*	*10.00*	Revenues per sh	*10.50*
3.51	3.20	3.60	3.59	3.84	4.26	5.10	4.71	3.47	3.66	4.59	4.84	4.64	4.58	3.78	4.28	*3.75*	*3.90*	"Cash Flow" per sh	*4.50*
1.79	1.54	1.84	1.87	1.92	2.29	2.63	2.45	1.19	2.29	2.61	2.61	2.38	2.38	2.37	2.79	*2.20*	*2.30*	Earnings per sh A	*2.75*
.53	.72	.77	.82	.96	1.10	1.22	1.34	1.38	1.40	1.40	1.44	1.47	1.49	1.50	1.52	*1.58*	*1.64*	Div'd Decl'd per sh B ■	*1.82*
2.99	2.74	2.17	1.94	2.13	3.62	4.51	3.79	3.25	3.30	4.30	5.34	6.68	6.14	5.24	4.30	*4.95*	*4.95*	Cap'l Spending per sh	*3.75*
6.33	6.71	9.19	11.21	11.62	13.30	14.88	13.55	14.57	16.98	18.72	18.01	19.78	20.47	14.72	14.56	*15.45*	*16.40*	Book Value per sh C	*19.75*
293.16	331.47	354.72	378.14	380.15	385.04	373.27	374.58	377.18	483.39	578.41	581.94	630.32	665.85	673.86	679.73	*690.00*	*700.00*	Common Shs Outst'g D	*730.00*
12.4	11.1	10.6	12.5	15.1	14.1	17.3	17.6	25.7	11.9	10.5	10.9	12.8	14.1	13.9	12.8	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.64	.61	.60	.66	.80	.76	.92	1.06	1.71	.76	.66	.69	.72	.74	.70	.67	*Value Line*		Relative P/E Ratio	*.95*
2.4%	4.2%	4.0%	3.5%	3.3%	3.4%	2.7%	3.1%	4.5%	5.1%	5.1%	5.1%	4.8%	4.4%	4.5%	4.2%	*estimates*		Avg Ann'l Div'd Yield	*4.4%*

CAPITAL STRUCTURE as of 9/30/16
Total Debt $19148 mill. Due in 5 Yrs $3104 mill.
LT Debt $18069 mill. LT Interest $741 mill.
Incl. 23 mill. units 7.75%, $25 liq. value; 82,000 units 8.23%, $1000 face value.
(LT interest earned: 3.7x)

Leases, Uncapitalized Annual rentals $33 mill.
Pension Assets-12/15 $10852 mill. Oblig $12267 mill.

Pfd Stock None
Common Stock 679,627,323 shs. as of 10/26/16
MARKET CAP: $24 billion (Large Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
6498.0	8044.0	7556.0	8521.0	12737	12286	11860	11499	7669.0	7517.0	*6800*	*7000*	Revenues ($mill)	*7600*
1031.0	940.0	465.0	1009.0	1456.0	1536.0	1541.0	1583.0	1603.0	1902.0	*1510*	*1625*	Net Profit ($mill)	*2015*
20.7%	31.8%	21.8%	22.0%	31.0%	26.2%	23.1%	33.0%	22.5%	25.4%	*27.0%*	*30.0%*	Income Tax Rate	*30.0%*
--	.1%	9.5%	3.5%	4.0%	4.1%	3.7%	2.8%	1.6%	1.0%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
54.1%	57.1%	55.2%	59.0%	61.9%	64.1%	62.3%	58.0%	65.2%	64.3%	*63.5%*	*63.0%*	Long-Term Debt Ratio	*58.0%*
43.6%	40.5%	42.5%	39.8%	37.2%	35.9%	37.7%	42.0%	34.8%	35.7%	*36.5%*	*37.0%*	Common Equity Ratio	*42.0%*
12747	12529	12940	20621	29071	29205	33058	32484	28482	27707	*29325*	*31025*	Total Capital ($mill)	*34300*
12605	12416	13174	20858	27266	30032	33087	34597	30382	30074	*32450*	*34800*	Net Plant ($mill)	*40000*
9.8%	9.2%	5.2%	6.1%	6.5%	7.0%	6.2%	6.5%	7.1%	8.5%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.5%*
17.6%	17.5%	8.0%	11.9%	13.1%	14.7%	12.4%	11.6%	16.2%	19.2%	*14.0%*	*14.0%*	Return on Shr. Equity	*14.0%*
18.2%	18.2%	8.1%	12.0%	13.3%	14.6%	12.4%	11.6%	16.2%	19.2%	*14.0%*	*14.0%*	Return on Com Equity E	*14.0%*
10.0%	8.5%	NMF	5.2%	6.4%	6.7%	5.3%	4.5%	6.0%	8.8%	*4.0%*	*4.0%*	Retained to Com Eq	*5.0%*
46%	54%	115%	58%	52%	54%	57%	61%	63%	54%	*72%*	*70%*	All Div'ds to Net Prof	*66%*

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	+1.2	-1.1	-.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	288	309	321

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '20-'22
Revenues	--	-4.5%	*NMF*
"Cash Flow"	1.5%	2.0%	*NMF*
Earnings	2.5%	4.0%	*NMF*
Dividends	5.5%	1.5%	*3.0%*
Book Value	5.5%	4.0%	*NMF*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	1194	2833	3449	4023	11499
2015	2230	1781	1878	1780	7669
2016	2011	1785	1889	1832	7517
2017	*1900*	*1600*	*1700*	*1600*	*6800*
2018	*1950*	*1650*	*1750*	*1650*	*7000*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.50	.32	.73	.82	2.38
2015	.82	.37	.59	.60	2.37
2016	.71	.71	.69	.68	2.79
2017	*.70*	*.45*	*.55*	*.50*	*2.20*
2018	*.70*	*.50*	*.55*	*.55*	*2.30*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.36	.3675	.3675	.3675	1.46
2014	.3675	.3725	.3725	.3725	1.49
2015	.3725	.3725	.3725	.3775	1.50
2016	.3775	.38	.38	.38	1.52
2017	.38	.395			

BUSINESS: PPL Corporation (formerly PP&L Resources, Inc.) is a holding company for PPL Electric Utilities (formerly Pennsylvania Power & Light Company), which distributes electricity to 1.4 million customers in eastern & central PA. Acq'd Kentucky Utilities and Louisville Gas and Electric (1.2 million customers) 11/10. Has electric distribution sub. in U.K. (7.8 million customers). Sold gas distribution subsidiary in '08. Spun off power generating subsidiary in '15. The company no longer breaks out data on electric operating statistics. Fuel costs: 22% of revs. '15 reported deprec. rate: 2.6%. Has 12,800 employees. Chairman, President & CEO: William H. Spence. Inc.: PA. Address: Two North Ninth St., Allentown, PA 18101-1179. Tel.: 800-345-3085. Internet: www.pplweb.com.

PPL Corporation's earnings will probably decline this year. The company has exposure to the British pound through its ownership of electric utilities in the United Kingdom. A negative factor will be the absence of a settlement of currency contracts in 2016, which boosted the bottom line by $0.30 a share. In addition, the hedged exchange rate for 2017 will be lower than it was last year. (Note that PPL has hedged the exchange rate to as low as $0.90/£ through 2019.) Some tax benefits booked in 2016 are not expected to recur. And average shares outstanding will be higher, as PPL plans to issue about $350 million of common equity annually through 2020 to finance its increased capital budget. Our 2017 earnings estimate is within PPL's targeted range of $2.05-$2.25 a share. Despite the expectation of lower earnings . . .

The board of directors raised the dividend. The increase was $0.06 a share (3.9%) yearly, payable in early April. PPL is projecting similar annual dividend growth through 2020.

We forecast a partial profit recovery in 2018. The utilities in Kentucky expect to obtain rate hikes in mid-2017 (see below), so the company will book a full year's effect of rate relief in 2018. Also, PPL's utilities benefit from regulatory mechanisms that provide recovery of 70% of the company's capital spending within six months. PPL's goal is 5%-6% annual earnings growth beginning next year, and our 2018 forecast of $2.30 would produce an increase that approaches this range.

PPL's utilities in Kentucky have rate cases pending. Kentucky Utilities is seeking an electric rate hike of $103.1 million (6.4%). Louisville Gas and Electric filed for electric and gas increases of $93.6 million (8.5%) and $13.8 million (4.2%), respectively. The applications are based on a 10.23% return on equity. New tariffs are expected to take effect in mid-2017.

The dividend yield of PPL stock is a percentage point above the utility average. Total return potential to 2020-2022 is also above average for the industry. The stock is unranked for Timeliness due to the spinoff of PPL's nonregulated operations in 2015, which made year-to-year earnings comparisons misleading.

Paul E. Debbas, CFA *February 17, 2017*

(A) Dil. EPS. Excl. nonrec. gain (losses): '07, (12¢); '10, (8¢); '11, 8¢; '13, (62¢); gains (losses) on disc. ops.: '07, 19¢; '08, 3¢; '09, (10¢); '10, (4¢); '12, (1¢); '14, 23¢; '15, ($1.36). '14 & '15 EPS don't sum to rounding. Next earnings report due early May. (B) Div'ds histor. pd. in early Jan., Apr., July, & Oct. ■ Div'd reinv. plan avail. (C) Incl. intang. In '15: $8.85/sh. (D) In mill., adj. for split. (E) Rate base: Fair val. Rate all'd on com. eq. in PA in '16: none spec.; in KY in '15: none spec.; earn. on avg. com. eq., '15: 13.0%. Reg. Clim.: Avg.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	10
Earnings Predictability	65

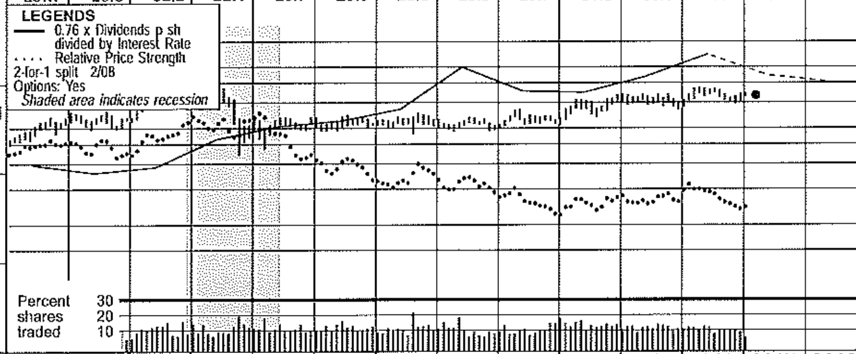
P.S. ENTERPRISE GP. NYSE-PEG

RECENT PRICE 43.45 | P/E RATIO 15.2 (Trailing: 15.3 Median: 13.0) | RELATIVE P/E RATIO 0.78 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 2 Raised 8/12/16
SAFETY 1 Raised 11/23/12
TECHNICAL 3 Raised 2/10/17
BETA .70 (1.00 = Market)

High:	36.3	49.9	52.3	34.1	34.9	35.5	34.1	37.0	43.8	44.4	47.4	44.7
Low:	29.5	32.2	22.1	23.7	29.0	28.0	28.9	29.7	31.3	36.8	37.8	42.9

Target Price Range 2020 | 2021 | 2022



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+40%)	12%
Low	45	(+5%)	5%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	1	1	1	1	1	1	1	1	1
to Sell	1	4	2	1	2	1	1	1	1

Institutional Decisions

	1Q2016	2Q2016	3Q2016
to Buy	333	314	280
to Sell	284	294	299
Hld's(000)	341192	333293	326956

% TOT. RETURN 1/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	11.3	31.2
3 yr.	49.1	25.8
5 yr.	79.3	84.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
23.84	18.62	23.54	23.09	24.74	24.07	25.28	27.94	24.57	23.31	22.42	19.33	19.71	21.52	20.61	*18.30*	*18.60*	*18.95*	Revenues per sh	*21.75*
3.14	3.01	2.92	3.02	3.42	3.91	4.36	4.68	4.98	5.27	5.36	4.87	5.17	5.82	6.15	*5.85*	*6.15*	*6.40*	"Cash Flow" per sh	*7.75*
1.85	1.88	1.88	1.52	1.79	1.85	2.59	2.90	3.08	3.07	3.11	2.44	2.45	2.99	3.30	*2.75*	*2.85*	*2.90*	Earnings per sh A	*3.50*
1.08	1.08	1.08	1.10	1.12	1.14	1.17	1.29	1.33	1.37	1.37	1.42	1.44	1.48	1.56	1.64	*1.72*	*1.80*	Div'd Decl'd per sh B ■†	*2.10*
4.99	4.03	2.86	2.64	2.04	2.01	2.65	3.50	3.55	4.27	4.12	5.09	5.56	5.58	7.65	*7.30*	*6.90*	*6.15*	Cap'l Spending per sh	*5.25*
10.05	8.85	11.71	12.05	11.99	13.35	14.35	15.36	17.37	19.04	20.30	21.31	22.95	24.09	25.86	*26.00*	*26.05*	*27.20*	Book Value per sh C	*31.25*
411.68	450.53	472.27	476.20	502.33	505.29	508.52	506.02	505.99	505.97	505.95	505.89	505.86	505.84	505.28	*506.00*	*506.00*	*506.00*	Common Shs Outst'g D	*506.00*
12.0	10.0	10.6	14.3	16.5	17.8	16.5	13.6	10.0	10.4	10.4	12.8	13.5	12.6	12.4	*15.8*	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.61	.55	.60	.76	.88	.96	.88	.82	.67	.66	.65	.81	.76	.66	.62	*.85*	*Value Line*		Relative P/E Ratio	*.95*
4.9%	5.7%	5.4%	5.1%	3.8%	3.5%	2.7%	3.3%	4.3%	4.3%	4.2%	4.6%	4.4%	3.9%	3.8%	3.8%	*estimates*		Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 9/30/16
Total Debt $10952 mill. Due in 5 Yrs $3755 mill.
LT Debt $10697 mill. LT Interest $428 mill.
(LT interest earned: 7.6x)

Leases, Uncapitalized Annual rentals $29 mill.

Pension Assets-12/15 $5039 mill. Oblig $5522 mill.

Pfd Stock None

Common Stock 505,896,218 shs. as of 10/16/16

MARKET CAP: $22 billion (Large Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
12853	14139	12431	11793	11343	9781.0	9968.0	10886	10415	*9250*	*9400*	*9600*	Revenues ($mill)	*11000*
1323.0	1477.0	1567.0	1557.0	1577.0	1239.0	1243.0	1518.0	1679.0	*1400*	*1465*	*1490*	Net Profit ($mill)	*1805*
44.5%	45.9%	42.3%	40.5%	40.4%	36.2%	39.5%	38.2%	37.4%	*36.5%*	*37.0%*	*37.0%*	Income Tax Rate	*37.0%*
2.7%	3.2%	3.8%	5.5%	2.7%	4.8%	4.6%	4.5%	5.5%	*5.0%*	*5.0%*	*4.0%*	AFUDC % to Net Profit	*4.0%*
54.0%	50.5%	46.3%	44.8%	42.1%	38.3%	40.4%	40.4%	40.3%	*42.0%*	*43.5%*	*44.5%*	Long-Term Debt Ratio	*47.0%*
45.5%	49.0%	53.2%	55.2%	57.9%	61.7%	59.6%	59.6%	59.7%	*58.0%*	*56.5%*	*55.5%*	Common Equity Ratio	*53.0%*
16041	15856	16513	17452	17731	17467	19470	20446	21900	*22575*	*23325*	*24700*	Total Capital ($mill)	*29700*
13275	14433	15440	16390	17849	19736	21645	23589	26539	*28400*	*29750*	*31150*	Net Plant ($mill)	*32900*
10.4%	11.2%	11.0%	10.4%	10.2%	8.1%	7.5%	8.4%	8.6%	*7.0%*	*7.0%*	*7.0%*	Return on Total Cap'l	*7.0%*
17.9%	18.8%	17.7%	16.2%	15.4%	11.5%	10.7%	12.5%	12.9%	*10.5%*	*11.0%*	*11.0%*	Return on Shr. Equity	*11.5%*
18.1%	19.0%	17.8%	16.2%	15.4%	11.5%	10.7%	12.5%	12.9%	*10.5%*	*11.0%*	*11.0%*	Return on Com Equity E	*11.5%*
9.9%	10.5%	10.1%	9.0%	8.6%	4.8%	4.4%	6.3%	6.8%	*4.5%*	*4.5%*	*4.0%*	Retained to Com Eq	*4.5%*
45%	45%	43%	45%	44%	58%	59%	49%	47%	*59%*	*59%*	*61%*	All Div'ds to Net Prof	*59%*

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	-.9	-1.3	+2.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH(¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	10414	9474	9595
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	529	635	705

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '20-'22
Revenues	-1.5%	-4.0%	*1.0%*
"Cash Flow"	6.0%	3.0%	*4.5%*
Earnings	5.5%	-.5%	*2.5%*
Dividends	3.0%	2.5%	*5.0%*
Book Value	7.5%	7.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	3223	2249	2641	2773	10886
2015	3135	2314	2688	2278	10415
2016	2616	1905	2450	*2279*	*9250*
2017	*2700*	*1950*	*2500*	*2250*	*9400*
2018	*2750*	*2000*	*2550*	*2300*	*9600*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.76	.42	.87	.94	2.99
2015	1.15	.68	.87	.60	3.30
2016	.93	.37	.94	*.51*	*2.75*
2017	*.95*	*.60*	*.80*	*.50*	*2.85*
2018	*1.00*	*.60*	*.80*	*.50*	*2.90*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.36	.36	.36	.36	1.44
2014	.37	.37	.37	.37	1.48
2015	.39	.39	.39	.39	1.56
2016	.41	.41	.41	.41	1.64
2017					

BUSINESS: Public Service Enterprise Group Incorporated is a holding company for Public Service Electric and Gas Company (PSE&G), which serves 2.2 million electric and 1.8 million gas customers in New Jersey, and PSEG Power LLC, a nonregulated power generator with nuclear, gas, and coal-fired plants in the Northeast. PSEG Energy Holdings is involved in renewable energy. The company no longer breaks out data on electric and gas operating statistics. Fuel costs: 31% of revenues. '15 reported depreciation rate (utility): 2.5%. Has 12,700 employees. Chairman, President & Chief Executive Officer: Dr. Ralph Izzo. Inc.: New Jersey. Address: 80 Park Plaza, P.O. Box 1171, Newark, New Jersey 07101-1171. Telephone: 973-430-7000. Internet: www.pseg.com.

Public Service Enterprise Group's utility subsidiary has become the main source of income—and earnings growth — for the company. Several years ago, this was not the case. PSEG's main nonutility subsidiary, PSEG Power, generated the bulk of corporate profits. That was when conditions in the power markets were more favorable for owners of merchant (i.e., noncontracted) generating assets than they are today. PSEG Power has managed well through the downturn, but has not been immune to difficult market conditions. On the other hand, Public Service Electric and Gas' investments in transmission and distribution infrastructure are expanding the utility's rate base. PSE&G has a storm-hardening program that was developed after Hurricane Sandy hit the service area in the fall of 2012. Most of these expenditures are recoverable in rates concurrently, which lessens the effects of regulatory lag. Electric transmission is a key growth area for the utility. The allowed return on equity for transmission is greater than that for distribution.

This is not to say that there is no growth at PSEG Power. This unit will spend an estimated $1.975 billion-$2.125 billion on three gas-fired facilities (1,780 megawatts in all) in Maryland, New Jersey, and Connecticut. The plants will come on line in 2018 and 2019.

PSE&G received a rate increase at the start of the new year, and another filing will occur at the start of November. Every year, the utility's transmission business receives rate relief from the Federal Energy Regulatory Commission through a forward-looking formula rate plan. This year's increase is $121 million. PSE&G will file an electric and gas rate case in November, in which it will seek recovery of costs that aren't subject to regulatory tracking mechanisms.

We think the board of directors raised the dividend shortly after this report went to press. We estimate a boost of two cents a share (4.9%) quarterly, the same hike as in each of the past two years.

This timely stock is suitable for conservative utility investors. It has our top rank for Safety. The dividend yield and 3- to 5-year total return potential are each above the utility averages.

Paul E. Debbas, CFA February 17, 2017

(A) Diluted EPS. Excl. nonrecur. gain (losses): '02, ($1.30); '05, (3¢); '06, (35¢); '08, (96¢); '09, 6¢; '11, (34¢); '12, 7¢; '16, (30¢); gains (loss) from disc. ops.: '05, (33¢); '06, 12¢; '07, 3¢; '08, 40¢; '11, 13¢. Next egs. report due late Feb. (B) Div'ds histor. paid in late Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. intang. In '15: $6.56/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '10: 10.3%; earned on avg. com. eq., '15: 13.2%. Reg. Climate: Avg.

Company's Financial Strength	A++
Stock's Price Stability	95
Price Growth Persistence	20
Earnings Predictability	65

SCANA CORP. NYSE-SCG

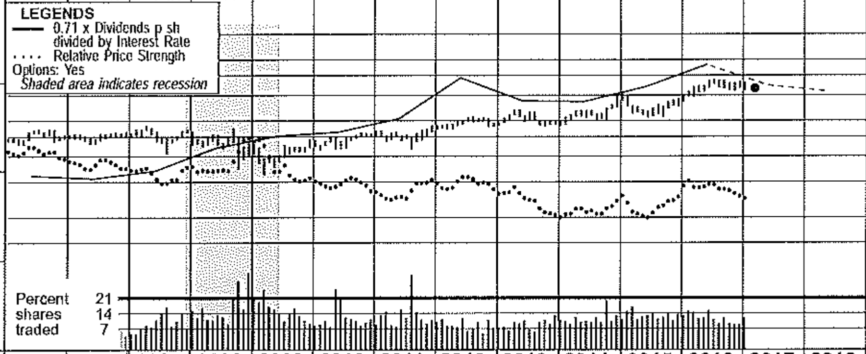
RECENT PRICE 69.49 | P/E RATIO 17.1 (Trailing: 17.5; Median: 14.0) | RELATIVE P/E RATIO 0.88 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 3 Lowered 1/20/17
SAFETY 2 Lowered 9/10/99
TECHNICAL 1 Raised 2/10/17
BETA .65 (1.00 = Market)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
High:	42.4	45.5	44.1	38.6	42.0	45.5	50.3	54.4	63.4	65.6	76.4	74.1
Low:	36.9	32.9	27.8	26.0	34.2	34.6	43.3	44.7	45.6	49.9	59.5	67.6

Target Price Range 2020 | 2021 | 2022

LEGENDS
— 0.71 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+20%)	9%
Low	60	(-15%)	1%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	2	0	1	2	2	0	2	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2016	2Q2016	3Q2016
to Buy	255	241	201
to Sell	172	203	215
Hld's(000)	95492	93877	92291

% TOT. RETURN 1/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	12.8	31.2
3 yr.	62.8	25.8
5 yr.	86.8	84.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
32.95	26.65	30.85	34.53	41.66	39.11	39.61	45.16	34.35	36.10	33.95	31.63	31.88	34.70	30.65	*28.70*	*29.05*	*30.00*	Revenues per sh	*33.50*
4.55	4.56	4.95	5.28	7.43	5.68	5.73	5.86	5.63	5.91	6.01	6.30	6.53	6.91	6.70	*7.05*	*7.35*	*7.55*	"Cash Flow" per sh	*9.00*
2.15	2.38	2.50	2.67	2.78	2.59	2.74	2.95	2.85	2.98	2.97	3.15	3.39	3.79	3.81	*4.00*	*4.15*	*4.35*	Earnings per sh A	*5.00*
1.20	1.30	1.38	1.46	1.56	1.68	1.76	1.84	1.88	1.90	1.94	1.98	2.03	2.10	2.18	2.30	*2.42*	*2.54*	Div'd Decl'd per sh B ■ †	*2.90*
4.99	6.41	6.94	4.86	3.38	4.52	6.21	7.68	7.41	6.87	6.81	8.16	7.84	7.65	8.07	*11.55*	*15.45*	*11.70*	Cap'l Spending per sh	*8.75*
20.95	19.64	20.82	21.78	23.35	24.39	25.37	25.85	27.63	29.05	29.94	31.47	33.08	34.95	38.09	*39.80*	*41.60*	*43.70*	Book Value per sh C	*50.00*
104.73	110.83	110.74	112.52	114.67	116.67	116.67	117.78	123.34	127.45	129.88	132.01	141.00	142.70	142.90	*142.90*	*142.90*	*145.00*	Common Shs Outst'g D	*149.00*
12.6	12.2	13.0	13.6	14.4	15.4	15.0	12.7	11.6	12.9	13.7	14.8	14.4	13.7	14.7	17.5	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*14.5*
.65	.67	.74	.72	.77	.83	.80	.76	.77	.82	.86	.94	.81	.72	.74	.90			Relative P/E Ratio	*.90*
4.4%	4.5%	4.2%	4.0%	3.9%	4.2%	4.3%	4.9%	5.7%	4.9%	4.8%	4.2%	4.2%	4.1%	3.9%	3.3%			Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 9/30/16
Total Debt $7367 mill. **Due in 5 Yrs** $2009 mill.
LT Debt $6472 mill. LT Interest $355 mill.
(LT interest earned: 3.6x)

Leases, Uncapitalized Annual rentals $10 mill.
Pension Assets-12/15 $781.7 mill.
Oblig $855.4 mill.

Pfd Stock None

Common Stock 142,916,917 shs.
as of 10/31/16
MARKET CAP: $9.9 billion (Large Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
4621.0	5319.0	4237.0	4601.0	4409.0	4176.0	4495.0	4951.0	4380.0	*4100*	*4150*	*4350*	Revenues ($mill)	*5000*
327.0	353.0	357.0	376.0	387.0	420.0	471.0	538.0	544.0	*575*	*600*	*630*	Net Profit ($mill)	*750*
29.2%	35.4%	32.0%	29.8%	30.3%	30.2%	32.1%	31.6%	31.8%	*32.0%*	*32.0%*	*32.0%*	Income Tax Rate	*33.0%*
4.6%	8.5%	14.3%	8.0%	5.4%	7.6%	8.7%	9.1%	7.7%	*8.0%*	*10.0%*	*8.0%*	AFUDC % to Net Profit	*3.0%*
48.4%	58.0%	56.8%	52.9%	54.3%	54.4%	53.6%	52.6%	51.9%	*53.5%*	*53.5%*	*56.5%*	Long-Term Debt Ratio	*53.5%*
49.7%	40.5%	43.2%	47.1%	45.7%	45.6%	46.4%	47.4%	48.1%	*46.5%*	*46.5%*	*43.5%*	Common Equity Ratio	*45.5%*
5952.0	7519.0	7891.0	7854.0	8511.0	9103.0	10059	10518	11325	*12175*	*12750*	*14525*	Total Capital ($mill)	*16000*
7538.0	8305.0	9009.0	9662.0	10047	10896	11643	12232	13425	*14650*	*16400*	*17625*	Net Plant ($mill)	*20100*
7.3%	6.2%	6.1%	6.5%	6.2%	6.3%	6.2%	6.6%	6.2%	*6.0%*	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
10.6%	11.2%	10.5%	10.2%	10.0%	10.1%	10.1%	10.8%	10.0%	*10.0%*	*10.0%*	*10.0%*	Return on Shr. Equity	*10.0%*
10.8%	11.4%	10.2%	10.2%	10.0%	10.1%	10.1%	10.8%	10.0%	*10.0%*	*10.0%*	*10.0%*	Return on Com Equity E	*10.0%*
4.0%	4.4%	3.6%	3.8%	3.6%	3.9%	4.1%	4.9%	4.3%	*4.5%*	*4.5%*	*4.0%*	Retained to Com Eq	*4.5%*
64%	62%	66%	63%	64%	61%	60%	55%	57%	*57%*	*58%*	*58%*	All Div'ds to Net Prof	*57%*

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	+.3	+4.7	-.9
Avg. Indust. Use (MWH)	8180	NA	NA
Avg. Indust. Revs. per KWH (¢)	7.27	NA	NA
Capacity at Yearend (Mw)	5237	5237	5234
Peak Load, Summer (Mw)	4574	4853	4970
Annual Load Factor (%)	58.8	NA	NA
% Change Customers (yr-end)	+1.2	+1.4	+1.5
Fixed Charge Cov. (%)	293	307	323

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '20-'22
Revenues	-1.0%	-3.5%	*.5%*
"Cash Flow"	1.5%	3.0%	*4.5%*
Earnings	3.5%	4.5%	*4.5%*
Dividends	3.5%	2.5%	*4.5%*
Book Value	5.0%	5.0%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	1590	1026	1121	1214	4951.0
2015	1389	967	1068	956	4380.0
2016	1172	905	1093	*930*	*4100*
2017	*1200*	*950*	*1000*	*1000*	*4150*
2018	*1250*	*1000*	*1050*	*1050*	*4350*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	1.37	.68	1.01	.73	3.79
2015	1.39	.69	1.04	.69	3.81
2016	1.23	.74	1.32	*.71*	*4.00*
2017	*1.35*	*.75*	*1.25*	*.80*	*4.15*
2018	*1.40*	*.80*	*1.30*	*.85*	*4.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.495	.5075	.5075	.5075	2.02
2014	.5075	.525	.525	.525	2.08
2015	.525	.545	.545	.545	2.16
2016	.545	.575	.575	.575	2.27
2017	.575				

BUSINESS: SCANA Corporation is a holding company for South Carolina Electric & Gas Company, which supplies electricity to 707,000 customers in central, southern, and southwestern South Carolina. Supplies gas service to 1.3 million customers in North Carolina, South Carolina, and Georgia. Electric revenue breakdown: residential, 44%; commercial, 33%; industrial, 18%; other, 5%. Generating sources: coal, 48%; oil & gas, 28%; nuclear, 19%; hydro, 3%; purchased, 2%. Fuel costs: 46% of revenues. '15 reported depreciation rate: 2.6%. Has 5,800 employees. Chairman, CEO & President: Kevin B. Marsh. Incorporated: South Carolina. Address: 100 SCANA Parkway, Cayce, South Carolina 29033. Telephone: 803-217-9000. Internet: www.scana.com.

SCANA's electric utility subsidiary has fixed the price of the two nuclear units under construction. Units 2 and 3 of the Summer plant are expected to come on line in August of 2019 and August of 2020. The project has had delays and cost overruns, so last fall South Carolina Electric & Gas chose to exercise its option to fix the cost at $7.658 billion. This represented an increase of $831 million, but reduced uncertainty about the project. Any excess costs will be absorbed by the contractor, Westinghouse. However . . .

There is still some risk associated with the project. Toshiba, the parent of Westinghouse, is experiencing financial troubles and has had its credit ratings downgraded by the rating agencies. If problems arise that make Westinghouse unable to complete construction, SCE&G has contingency plans and some forms of protection, such as surety bonds. In any case, the market appears to be taking the construction risks in stride. SCANA stock's 25.0% total return in 2016 put the equity in the upper half for the electric utility industry, and exceeded the group median of 18.7%.

Rate relief should enable earnings to climb in 2017 and 2018. Every year, SCE&G receives a rate hike under the state's Base Load Review Act for its construction work in progress for the aforementioned nuclear units. The most recent increase was $64.4 million (2.7%), last November. This year, SCE&G and PSNC Energy will have a full year's benefit of the gas rate increases that took effect in November of 2016.

We think the board of directors raised the dividend shortly after this report went to press. In recent years, the board has reviewed the dividend in mid-February. We estimate an increase of $0.03 a share (5.2%), the same hike as a year ago, effective with the April payment. SCANA is targeting a payout ratio in a range of 55%-60%.

SCANA stock has a valuation that is typical for a utility. The dividend yield is near the industry average. Like most utility issues, the recent quotation is within our 3- to 5-year Target Price Range. Total return potential over that time frame is also average for the group.

Paul E. Debbas, CFA *February 17, 2017*

(A) Diluted earnings. Excl. nonrecurring gains (losses): '01, $3.00; '02, ($3.72); '03, 31¢; '04, (23¢); '05, 3¢; '06, 9¢; '15, $1.41. Next earnings report due late April. (B) Div'ds historically paid in early Jan., Apr., July, & Oct. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '15: $13.55/sh. (D) In millions. (E) Rate base: Net original cost. Rate allowed on com. eq. in SC: 10.25% elec. in '13, 10.25% gas in '05; in NC: 9.7% in '16; earned on avg. com. eq., '15: 10.6%. Regulatory Climate: Above Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	55
Earnings Predictability	100

SEMPRA ENERGY NYSE-SRE

RECENT PRICE 103.40 | P/E RATIO 20.2 (Trailing: 25.7; Median: 13.0) | RELATIVE P/E RATIO 1.02 | DIV'D YLD 3.2% | VALUE LINE

TIMELINESS 3 Lowered 10/28/16
SAFETY 2 Raised 7/29/16
TECHNICAL 4 Lowered 12/30/16
BETA .80 (1.00 = Market)

High:	47.9	57.3	66.4	63.0	57.2	57.2	56.0	72.9	93.0	116.3	116.2	114.7
Low:	35.5	42.9	50.9	34.3	36.4	43.9	44.8	54.7	70.6	86.7	89.4	86.7

Target Price Range 2019 | 2020 | 2021

2019-21 PROJECTIONS

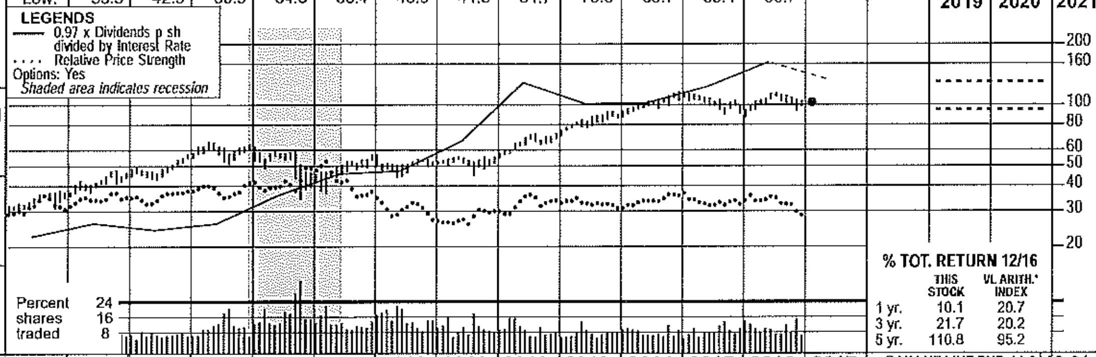
	Price	Gain	Ann'l Total Return
High	130	(+25%)	9%
Low	95	(-10%)	2%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	1
Options	1	0	4	1	1	1	0	0	0
to Sell	2	0	1	1	0	2	0	0	0

Institutional Decisions

	1Q2016	2Q2016	3Q2016
to Buy	270	266	227
to Sell	254	249	253
Hld's(000)	203184	199665	200473



% TOT. RETURN 12/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	10.1	20.7
3 yr.	21.7	20.2
5 yr.	110.8	95.2

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
35.38	39.27	29.38	34.81	40.18	45.64	44.69	43.79	44.21	32.88	37.44	41.83	39.80	43.18	44.80	41.20	39.85	40.70	Revenues per sh	48.25
4.91	5.39	5.71	5.56	6.58	5.96	6.74	6.93	7.40	7.94	7.76	8.58	8.92	8.87	9.41	10.32	9.25	11.00	"Cash Flow" per sh	14.25
2.06	2.55	2.79	3.01	3.93	3.52	4.23	4.26	4.43	4.78	4.02	4.47	4.35	4.22	4.63	5.23	3.85	5.20	Earnings per sh A	7.50
1.00	1.00	1.00	1.00	1.00	1.16	1.20	1.24	1.37	1.56	1.56	1.92	2.40	2.52	2.64	2.80	3.02	3.28	Div'd Decl'd per sh B ■	4.00
3.76	5.22	5.92	4.63	4.62	5.46	7.28	7.70	8.47	7.76	8.58	11.85	12.20	10.52	12.68	12.71	14.15	10.30	Cap'l Spending per sh	11.25
12.35	13.17	13.79	17.17	20.78	23.95	28.66	31.67	32.75	36.54	37.54	41.00	42.42	45.03	45.98	47.56	49.40	51.20	Book Value per sh C	56.25
201.90	204.48	204.91	226.60	234.18	257.19	262.01	261.21	243.32	246.51	240.45	239.93	242.37	244.46	246.33	248.30	251.00	253.00	Common Shs Outst'g D	242.00
9.4	9.7	8.2	9.0	8.6	11.8	11.5	14.0	11.8	10.1	12.6	11.8	14.9	19.7	21.9	19.7	26.8		Avg Ann'l P/E Ratio	15.0
.61	.50	.45	.51	.45	.63	.62	.74	.71	.67	.80	.74	.95	1.11	1.15	1.00	1.40		Relative P/E Ratio	.95
5.2%	4.1%	4.4%	3.7%	2.9%	2.8%	2.5%	2.1%	2.6%	3.2%	3.1%	3.6%	3.7%	3.0%	2.6%	2.7%	2.9%		Avg Ann'l Div'd Yield	3.5%

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
	11761	11438	10758	8106.0	9003.0	10036	9647.0	10557	11035	10231	10000	10300	Revenues ($mill)	11700
	1118.0	1135.0	1123.0	1193.0	1008.0	1088.0	1079.0	1060.0	1162.0	1314.0	1025	1425	Net Profit ($mill)	1930
	31.3%	33.6%	29.2%	30.5%	26.5%	25.3%	18.2%	26.5%	19.7%	19.2%	29.5%	29.0%	Income Tax Rate	28.0%
	7.2%	11.5%	13.2%	10.6%	11.3%	15.2%	17.2%	11.2%	14.4%	15.3%	21.0%	14.0%	AFUDC % to Net Profit	10.0%
	37.0%	34.8%	44.5%	44.8%	49.4%	50.4%	52.8%	50.5%	51.7%	52.6%	53.0%	53.0%	Long-Term Debt Ratio	57.5%
	61.4%	63.7%	54.2%	54.1%	49.6%	49.2%	46.7%	49.4%	48.2%	47.3%	47.0%	47.0%	Common Equity Ratio	42.5%
	12229	13071	14692	16646	18186	20015	22002	22281	23513	24963	26275	27700	Total Capital ($mill)	31900
	13175	14884	16865	18281	19876	23572	25191	25460	25902	28039	30250	31375	Net Plant ($mill)	34600
	10.3%	9.6%	8.5%	8.3%	6.8%	6.7%	6.1%	6.0%	6.1%	6.4%	5.0%	6.5%	Return on Total Cap'l	7.5%
	14.5%	13.3%	13.8%	13.0%	10.9%	10.9%	10.4%	9.6%	10.2%	11.1%	8.0%	10.0%	Return on Shr. Equity	13.5%
	14.8%	13.5%	14.0%	13.1%	11.1%	11.0%	10.4%	9.6%	10.3%	11.1%	8.0%	10.0%	Return on Com Equity E	13.5%
	11.0%	9.7%	9.7%	9.3%	7.0%	6.5%	5.1%	4.1%	5.0%	5.8%	2.0%	4.0%	Retained to Com Eq	6.0%
	26%	29%	31%	29%	37%	41%	52%	58%	52%	48%	77%	62%	All Div'ds to Net Prof	54%

CAPITAL STRUCTURE as of 9/30/16
Total Debt $17295 mill. Due in 5 Yrs $7861 mill.
LT Debt $13522 mill. LT Interest $566 mill.
Incl. $245 mill. capitalized leases.
(LT interest earned: 3.4x)

Leases, Uncapitalized Annual rentals $71 mill.
Pension Assets-12/15 $2484 mill. Oblig. $3649 mill.
Pfd Stock $20 mill. Pfd Div'd $1.2 mill.
811,073 shs. 6% cum., $25 par.
Common Stock 250,060,973 shs.
as of 10/27/16
MARKET CAP: $26 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	-1.3	+1.8	-1.0
Avg. Indust. Use (MWH)	4279	4543	4683
Avg. Indust. Revs. per KWH (¢)	13.10	16.55	17.58
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	NMF	NMF	NMF
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+.5	+.6	+.7
Fixed Charge Cov. (%)	307	288	295

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	.5%	2.5%	2.0%
"Cash Flow"	4.5%	4.5%	7.0%
Earnings	3.0%	1.5%	8.0%
Dividends	9.5%	12.0%	7.0%
Book Value	8.5%	5.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	2650	2651	2551	2705	10557
2014	2795	2678	2815	2747	11035
2015	2682	2367	2481	2701	10231
2016	2622	2156	2535	2687	10000
2017	2750	2250	2550	2750	10300

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.54	1.46	1.09	1.13	4.22
2014	.99	1.08	1.39	1.18	4.63
2015	1.74	1.03	.99	1.47	5.23
2016	1.47	.06	1.02	1.30	3.85
2017	1.75	1.05	1.05	1.35	5.20

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.60	.63	.63	.63	2.49
2014	.63	.66	.66	.66	2.61
2015	.66	.70	.70	.70	2.76
2016	.70	.755	.755	.755	2.97
2017					

BUSINESS: Sempra Energy is a holding co. for San Diego Gas & Electric Company, which sells electricity & gas mainly in San Diego County, & Southern California Gas Company, which distributes gas to most of Southern California. Customers: 1.4 mill. electric, 6.6 mill. gas. Elec. rev. breakdown: residential, 41%; commercial, 42%; industrial, 10%; other, 7%. Purchases most of its power; the rest is gas. Has subs. in gas pipeline & storage, power generation, & liquefied natural gas. Sold commodities business in '10. Power costs: 37% of revs. '15 reported deprec. rates: 2.7%-5.7%. Has 17,400 employees. Chairman and CEO: Debra L. Reed. President: Mark A. Snell. Inc.: CA. Address: 488 8th Avenue, San Diego, CA 92101. Tel.: 619-696-2000. Internet: www.sempra.com.

Sempra Energy's Cameron liquefied natural gas project is experiencing delays. The contractor now estimates that the three trains will be delayed until mid-2018, late 2018, and mid-2019. Previously, all three were expected to begin operating in 2018 and be in service for all of 2019. This will not affect the company's earnings this year, but will reduce its income in 2018 and 2019. (Quarterly profits when all three trains are in service are projected at $80 million.) Sempra might be eligible for damage payments due to the delay. Even so, this understandably concerns the market, and the stock has underperformed most utility issues since late October (when the announcement was made).

The year that just ended was an active one for dealmaking. Most notably, the company's Mexico subsidiary, IEnova, bought its partner's 50% stake in a midstream gas joint venture for $1.1 billion, and booked a $350 million (aftertax) nonrecurring gain in connection with the acquisition. IEnova also paid $852 million for a wind project. To help finance its investments, IEnova had a $1.6 billion equity offering. Sempra also raised $443 million through the sale of its 25% stake in the Rockies Express gas pipeline, but recorded a $27 million (aftertax) nonrecurring loss on the deal. Also in connection with this sale, the company recorded a $123 million charge for the permanent release of pipeline capacity, but we *included* this in our presentation due to its operational nature. That's why earnings in the second quarter of 2016 were depressed, and why the year-to-year profit comparison should be easy in 2017.

We expect a significant dividend hike at the board meeting in February. Sempra has set a goal of 8%-9% annual dividend growth through 2020, and we think the possible setback with Cameron will not change this target. We look for a raise of $0.065 a share (8.6%) in the quarterly payout.

The dividend yield of Sempra stock is below the industry average. This reflects the company's strong dividend growth potential. Like many utility equities, Sempra's recent quotation is within our 2019-2021 Target Price Range. Thus, total return potential is unspectacular.

Paul E. Debbas, CFA *January 27, 2017*

(A) Dil. EPS. Excl. nonrec. gains (losses): '05, 17¢; '06, (6¢); '09, (26¢); '10, ($1.05); '11, $1.15; '12, (98¢); '13, (30¢); '15, 14¢; '16, $1.23; gain (losses) from disc. ops.: '04, (10¢); '05, (4¢); '06, $1.21; '07, (10¢). '14 EPS don't sum due to rounding. Next egs. due late Feb. (B) Div'ds paid mid-Jan., Apr., July & Oct. ■ Div'd reinv. plan avail. (C) Incl. intang. In '15: $18.11/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq.: SDG&E in '13: 10.3%; SoCalGas in '13: 10.1%; earn. on avg. com. eq., '15: 11.2%. Regul. Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	80
Earnings Predictability	80

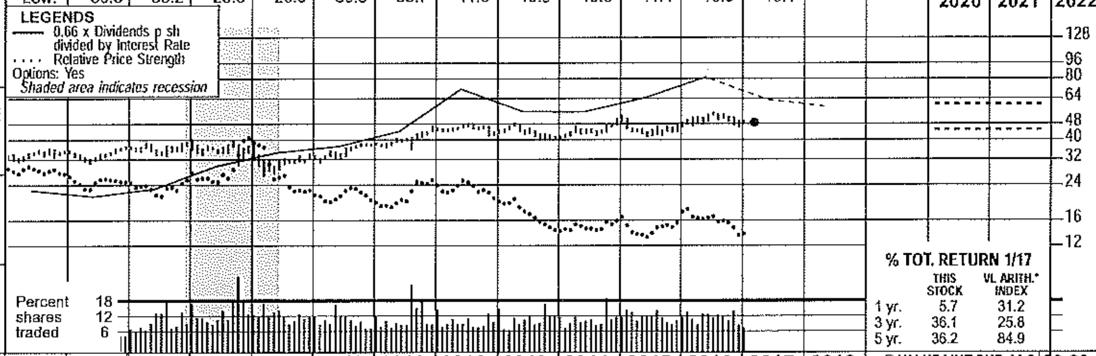
SOUTHERN COMPANY NYSE-SO

RECENT PRICE 48.76 | P/E RATIO 18.1 (Trailing: 16.7; Median: 16.0) | RELATIVE P/E RATIO 0.93 | DIV'D YLD 4.7% | VALUE LINE

TIMELINESS 2 Raised 3/18/16
SAFETY 2 Lowered 2/21/14
TECHNICAL 3 Raised 1/20/17
BETA .55 (1.00 = Market)

High:	37.4	39.3	40.6	37.6	38.6	46.7	48.6	48.7	51.3	53.2	54.6	49.8	
Low:	30.5	33.2	29.8	26.5	30.8	35.7	41.8	40.0	40.3	41.4	46.0	48.1	

Target Price Range 2020 | 2021 | 2022



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+25%)	10%
Low	45	(-10%)	3%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	1	1	2	4	3	0	0	0	0
to Sell	1	1	2	4	3	0	0	0	0

Institutional Decisions

	1Q2016	2Q2016	3Q2016
to Buy	587	564	524
to Sell	403	422	463
Hld's(000)	470025	478780	490983

% TOT. RETURN 1/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	5.7	31.2
3 yr.	36.1	25.8
5 yr.	36.2	84.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
14.54	14.73	15.31	16.05	18.28	19.24	20.12	22.04	19.21	20.70	20.41	19.06	19.26	20.34	19.18	**19.35**	**21.75**	**22.30**	Revenues per sh	**25.00**
3.55	3.46	3.53	3.65	4.03	4.01	4.22	4.43	4.43	4.51	4.91	5.18	5.27	5.28	5.47	**5.30**	**5.85**	**6.05**	"Cash Flow" per sh	**7.00**
1.61	1.85	1.97	2.06	2.13	2.10	2.28	2.25	2.32	2.36	2.55	2.67	2.70	2.77	2.84	**2.70**	**2.95**	**3.10**	Earnings per sh A	**3.75**
1.34	1.36	1.39	1.42	1.48	1.54	1.60	1.66	1.73	1.80	1.87	1.94	2.01	2.08	2.15	2.22	**2.30**	**2.38**	Div'd Decl'd per sh B ■ †	**2.62**
3.75	3.79	2.72	2.85	3.20	4.01	4.65	5.10	5.70	4.85	5.23	5.54	6.16	6.58	6.22	**10.30**	**8.85**	**8.10**	Cap'l Spending per sh	**7.25**
11.43	12.16	13.13	13.86	14.42	15.24	16.23	17.08	18.15	19.21	20.32	21.09	21.43	21.98	22.59	**28.60**	**29.55**	**30.50**	Book Value per sh C	**33.50**
698.34	716.40	734.83	741.50	741.45	746.27	763.10	777.19	819.65	843.34	865.13	867.77	887.09	907.78	911.72	**991.00**	**1003.0**	**1015.0**	Common Shs Outst'g D	**1021.0**
14.6	14.6	14.8	14.7	15.9	16.2	16.0	16.1	13.5	14.9	15.8	17.0	16.2	16.0	15.8	**18.6**	*Bold figures are*	*Value Line estimates*	Avg Ann'l P/E Ratio	**14.5**
.75	.80	.84	.78	.85	.87	.85	.97	.90	.95	.99	1.08	.91	.84	.80	**.95**			Relative P/E Ratio	**.95**
5.7%	5.0%	4.7%	4.7%	4.4%	4.5%	4.4%	4.6%	5.5%	5.1%	4.6%	4.3%	4.6%	4.7%	4.8%	4.4%			Avg Ann'l Div'd Yield	**4.9%**
						15353	17127	15743	17456	17657	16537	17087	18467	17489	**19200**	**21800**	**22650**	Revenues ($mill)	**25500**
						1782.0	1807.0	1910.0	2040.0	2268.0	2415.0	2439.0	2567.0	2647.0	**2675**	**3050**	**3230**	Net Profit ($mill)	**3895**
						31.9%	33.6%	31.9%	33.5%	35.0%	35.6%	34.8%	33.8%	33.4%	**33.5%**	**33.5%**	**33.5%**	Income Tax Rate	**33.5%**
						9.5%	12.3%	14.9%	13.7%	10.2%	9.4%	11.6%	13.9%	13.2%	**13.0%**	**12.0%**	**11.0%**	AFUDC % to Net Profit	**9.0%**
						51.2%	53.9%	53.2%	51.2%	50.0%	49.9%	51.5%	49.5%	52.8%	**56.0%**	**56.5%**	**57.0%**	Long-Term Debt Ratio	**57.0%**
						44.9%	42.6%	43.6%	45.7%	47.1%	47.3%	45.8%	47.3%	44.0%	**42.0%**	**41.5%**	**41.0%**	Common Equity Ratio	**41.0%**
						27608	31174	34091	35438	37307	38653	41483	42142	46788	**67850**	**71400**	**75225**	Total Capital ($mill)	**83100**
						33327	35878	39230	42002	45010	48390	51208	54868	61114	**78675**	**84650**	**89850**	Net Plant ($mill)	**102700**
						7.9%	7.1%	6.9%	7.0%	7.2%	7.3%	6.8%	7.1%	6.6%	**5.0%**	**5.0%**	**5.5%**	Return on Total Cap'l	**5.5%**
						13.2%	12.6%	12.0%	11.8%	12.2%	12.5%	12.1%	12.1%	12.0%	**9.0%**	**10.0%**	**10.0%**	Return on Shr. Equity	**11.0%**
						14.0%	13.1%	12.4%	12.2%	12.5%	12.8%	12.5%	12.5%	12.6%	**9.0%**	**10.0%**	**10.0%**	Return on Com Equity E	**11.0%**
						4.3%	3.5%	3.2%	3.0%	3.4%	3.6%	3.2%	3.2%	3.1%	**1.5%**	**2.0%**	**2.5%**	Retained to Com Eq	**3.5%**
						70%	74%	75%	77%	73%	73%	75%	75%	76%	**81%**	**77%**	**76%**	All Div'ds to Net Prof	**70%**

CAPITAL STRUCTURE as of 9/30/16
Total Debt $45474 mill. Due in 5 Yrs NA
LT Debt $41550 mill. LT Interest $1454 mill.
(LT interest earned: 5.0x)
Leases, Uncapitalized Annual rentals $121 mill.
Pension Assets-12/15 $9234 mill. Ob $10542 mill.
Pfd Stock $1508 mill. Pfd Div'd $44 mill.
Incl. 1 mill. shs. 4.2%-5.44% cum. pfd. ($100 par); 1.52 mill. shs. 5.2%-5.83% cum. pfd. ($1 par); 2 mill. shs. 6.0% noncum. pfd. ($25 par); 4 mill. shs. 5.6%-6.5% noncum. pfd. ($100 par); 8 mill. shs. 5.63%-6.5% noncum. pfd. ($1 par).
Common Stock 979,999,480 shs.
MARKET CAP: $48 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	+.3	+3.3	-.7
Avg. Indust. Use (MWH)	3277	3384	3371
Avg. Indust. Revs. per KWH (¢)	6.08	6.37	5.88
Capacity at Yearend (Mw)	45502	46549	44223
Peak Load, Summer (Mw) F	33557	37234	36794
Annual Load Factor (%)	63.2	59.6	59.9
% Change Customers (yr-end)	+.7	+.8	+.9
Fixed Charge Cov. (%)	423	417	433

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '20-'22
Revenues	1.5%	-1.0%	3.5%
"Cash Flow"	3.5%	3.5%	4.0%
Earnings	3.0%	3.5%	4.5%
Dividends	4.0%	3.5%	3.5%
Book Value	5.0%	4.0%	6.0%

Cal-endar	QUARTERLY REVENUES ($mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	4644	4467	5339	4017	18467
2015	4183	4337	5401	3568	17489
2016	3965	4453	6264	**4518**	**19200**
2017	**5800**	**5200**	**6200**	**4600**	**21800**
2018	**6050**	**5400**	**6450**	**4750**	**22650**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.66	.68	1.08	.36	2.77
2015	.56	.71	1.16	.42	2.84
2016	.57	.71	1.22	**.20**	**2.70**
2017	**.65**	**.70**	**1.15**	**.45**	**2.95**
2018	**.70**	**.75**	**1.20**	**.45**	**3.10**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.49	.5075	.5075	.5075	2.01
2014	.5075	.525	.525	.525	2.08
2015	.525	.5425	.5425	.5425	2.15
2016	.5425	.56	.56	.56	2.22
2017					

BUSINESS: The Southern Company, through its subs., supplies electricity to 4.6 million customers in GA, AL, FL, and MS. Also has a competitive generation business. Acq'd AGL Resources (renamed Southern Company Gas, 4.5 mill. customers in GA, FL, NJ, IL, VA, & TN) 7/16. Electric rev. breakdown: residential, 38%; commercial, 32%; industrial, 19%; other, 11%. Retail revs. by state: GA, 50%; AL, 34%; FL, 9%; MS, 7%. Generating sources: gas & oil, 44%; coal, 32%; nuclear, 15%; hydro, 3%; purchased, 6%. Fuel costs: 31% of revs. '15 reported depr. rate (utility): 3.0%. Has 32,000 employees. Chairman, President and CEO: Thomas A. Fanning. Inc.: DE. Address: 30 Ivan Allen Jr. Blvd., N.W., Atlanta, GA 30308. Tel.: 404-506-0747. Internet: www.southerncompany.com.

The Georgia commission has approved a settlement regarding the construction of two units at Southern Company's Georgia Power subsidiary. The project, at the site of the utility's Vogtle station, has had delays and cost overruns. All of the project's $3.3 billion of construction costs through 2015 were deemed prudent. The in-service capital cost forecast was raised from $4.418 billion to $5.68 billion. (This figure excludes $2.422 billion of financing costs, which are recovered concurrently.) The utility will have the burden of proof for prudence for any construction costs exceeding $5.68 billion. Finally, the return on equity used for calculating nuclear cost recovery was reduced from 10.95% to 10%. The new units are scheduled to come on line in June of 2019 and June of 2020.

Mississippi Power expects its coal gasification plant to he in service by the end of this month. The project has had extensive delays and cost overruns far above a regulatory cap of $2.88 billion. Accordingly, the utility has taken nonrecurring charges since 2013, and we expect additional charges for the fourth quarter of 2016 and the first period of 2017.

Gulf Power has a rate case pending. The utility asked the Florida regulators for a $106.8 million increase, based on an 11% ROE. Gulf Power is asking for new tariffs to take effect in July of 2017.

Earnings should be much improved in 2017 after a depressed tally in 2016, and we forecast further growth in 2018. Last year, the company incurred expenses associated with the acquisition and integration of AGL Resources (renamed Southern Company Gas). Also, the mid-2016 timing of the purchase meant that Southern Company did not own the business in the seasonally strong first quarter. Our 2017 earnings estimate is within management's targeted range of $2.90-$3.02 a share. Rate relief and growth in Southern Power's contracted nonregulated generating assets should be positive factors each year, as well.

This timely stock has a dividend yield that is more than a percentage point above the utility average. Total return potential to 2020-2022 is a cut above the industry average.

Paul E. Debbas, CFA *February 17, 2017*

(A) Dil. EPS. Excl. nonrec. gain (losses): '03, 6¢; '09, (25¢); '13, (83¢); '14, (59¢); '15, (25¢); '16, (13¢). '14 & '15 EPS don't add due to rounding. Next earnings report due late Feb. (B) Div'ds paid in early Mar., June, Sept., and Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. def'd chgs. In '15: $8.24/sh. (D) In mill. (E) Rate base: AL, MS, fair value; FL, GA, orig. cost. All'd return on com. eq. (blended): 12.5%; earn. on avg. com. eq., '15: 12.7%. Regul. Climate: GA, AL Above Avg.; MS, FL Avg. (F) Winter peak in '14 & '15.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	35
Earnings Predictability	100

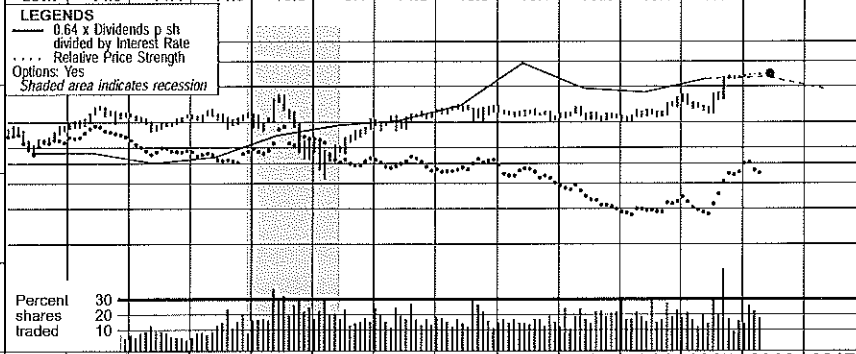
TECO ENERGY, INC. NYSE-TE

RECENT PRICE 27.76 | P/E RATIO 24.1 (Trailing: 25.9; Median: 16.0) | RELATIVE P/E RATIO 1.32 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS – Suspended 7/24/15
SAFETY 2 Raised 2/24/12
TECHNICAL – Suspended 7/24/15
BETA .80 (1.00 = Market)

High:	19.3	17.7	18.6	22.0	16.7	18.1	19.7	19.4	19.2	21.3	27.2	27.8
Low:	14.9	14.4	14.8	10.5	8.4	14.5	15.8	16.1	16.2	16.1	17.6	26.5

Target Price Range 2019 | 2020 | 2021



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	25	(-10%)	1%
Low	18	(-35%)	-6%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	1	0	0	0	0
Options	2	0	0	1	2	0	6	3	0
to Sell	1	0	0	0	1	0	0	3	1

Institutional Decisions

	2Q2015	3Q2015	4Q2015
to Buy	144	152	139
to Sell	161	199	189
Hld's(000)	139893	152870	154969

% TOT. RETURN 4/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	52.4	-3.4
3 yr.	66.5	29.5
5 yr.	82.3	47.7

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
18.17	18.97	15.22	14.59	13.37	14.46	16.46	16.77	15.85	15.48	16.23	15.49	13.83	13.12	10.93	11.66	*11.00*	*11.40*	Revenues per sh	*12.50*
4.11	4.31	3.20	1.96	2.14	2.37	2.51	2.51	2.01	2.35	2.59	2.77	2.69	2.43	2.36	2.51	*2.65*	*2.90*	"Cash Flow" per sh	*3.50*
1.97	2.24	1.95	d.08	.71	1.00	1.17	1.27	.77	1.00	1.13	1.27	1.14	.92	.95	1.03	*1.15*	*1.25*	Earnings per sh A	*1.50*
1.33	1.37	1.41	.93	.76	.76	.76	.78	.80	.80	.82	.85	.88	.88	.88	.90	*.92*	*.94*	Div'd Decl'd per sh B ■	*1.00*
5.45	6.92	6.06	3.14	1.37	1.42	2.18	2.34	2.77	2.99	2.28	2.10	2.33	2.45	3.04	3.14	*3.00*	*2.35*	Cap'l Spending per sh	*2.25*
11.93	14.12	14.86	8.93	6.43	7.65	8.25	9.56	9.43	9.75	10.10	10.50	10.58	10.74	10.96	10.88	*11.05*	*11.35*	Book Value per sh C	*12.50*
126.30	139.60	175.80	187.80	199.70	208.20	209.50	210.90	212.90	213.90	214.90	215.80	216.60	217.30	234.90	235.30	*236.00*	*237.00*	Common Shs Outst'g D	*240.00*
11.9	12.9	11.0	--	19.3	17.1	13.8	13.3	21.2	12.6	14.6	14.4	15.5	18.9	18.8	21.4	Bold figures are		Avg Ann'l P/E Ratio	*14.5*
.77	.66	.60	--	1.02	.91	.75	.71	1.28	.84	.93	.90	.99	1.06	.99	1.08	Value Line		Relative P/E Ratio	*.90*
5.7%	4.8%	6.6%	7.4%	5.5%	4.4%	4.7%	4.6%	4.9%	6.3%	4.9%	4.6%	5.0%	5.1%	4.9%	4.1%	estimates		Avg Ann'l Div'd Yield	*4.8%*

CAPITAL STRUCTURE as of 3/31/16
Total Debt $4086.0 mill. Due in 5 Yrs $1800.5 mill.
LT Debt $3489.7 mill. LT Interest $159.8 mill.
(LT interest earned: 3.2x)

Leases, Uncapitalized Annual rentals $7.7 mill.

Pension Assets-12/15 $625.4 mill. Oblig $732.9 mill.

Pfd Stock None

Common Stock 235,550,000 shs. as of 4/29/16
MARKET CAP: $6.5 billion (Large Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
3448.1	3536.1	3375.3	3310.5	3487.9	3343.4	2996.6	2851.3	2566.4	2743.5	*2600*	*2700*	Revenues ($mill)	*3000*
244.4	265.8	162.4	213.9	242.9	272.6	246.0	197.8	213.1	241.2	*265*	*290*	Net Profit ($mill)	*360*
40.4%	40.7%	36.8%	31.6%	34.8%	36.1%	35.9%	35.5%	38.3%	39.2%	*38.5%*	*38.5%*	Income Tax Rate	*38.5%*
1.6%	2.3%	5.4%	6.5%	1.2%	.6%	1.7%	5.0%	7.4%	10.8%	*11.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
65.0%	61.0%	61.5%	60.6%	59.2%	54.2%	56.5%	54.9%	56.6%	57.9%	*58.5%*	*58.5%*	Long-Term Debt Ratio	*58.0%*
35.0%	39.0%	38.5%	39.4%	40.8%	45.8%	43.5%	45.1%	43.4%	42.1%	*41.5%*	*41.5%*	Common Equity Ratio	*42.0%*
4941.6	5175.4	5214.3	5287.0	5317.8	4953.9	5264.5	5171.5	5928.7	6075.9	*6280*	*6450*	Total Capital ($mill)	*7175*
4766.9	4888.2	5221.3	5544.1	5841.0	5967.8	5990.1	6170.1	7088.2	7481.8	*7820*	*7985*	Net Plant ($mill)	*8275*
7.3%	7.3%	5.1%	6.0%	6.4%	7.4%	6.1%	5.4%	5.0%	5.3%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.5%*
14.1%	13.2%	8.1%	10.3%	11.2%	12.0%	10.7%	8.5%	8.3%	9.4%	*10.0%*	*11.0%*	Return on Shr. Equity	*12.0%*
14.1%	13.2%	8.1%	10.3%	11.2%	12.0%	10.7%	8.5%	8.3%	9.4%	*10.0%*	*11.0%*	Return on Com Equity E	*12.0%*
5.0%	5.1%	NMF	2.1%	3.1%	3.9%	2.4%	.3%	.5%	1.2%	*2.0%*	*2.5%*	Retained to Com Eq	*4.0%*
65%	61%	104%	80%	72%	67%	77%	97%	93%	88%	*82%*	*76%*	All Div'ds to Net Prof	*66%*

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	--	+.6	+2.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	8.50	8.65	8.57
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+1.5	+1.6	+1.8
Fixed Charge Cov. (%)	272	287	288

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	-1.5%	-5.5%	*1.0%*
"Cash Flow"	1.0%	1.0%	*6.5%*
Earnings	6.0%	--	*7.5%*
Dividends	1.0%	2.0%	*2.0%*
Book Value	3.5%	2.0%	*2.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	661.1	735.9	765.9	688.4	2851.3
2014	578.0	605.7	687.2	695.5	2566.4
2015	693.0	680.6	693.8	676.1	2743.5
2016	659.5	*640.5*	*650*	*650*	*2600*
2017	*675*	*675*	*675*	*675*	*2700*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.19	.24	.29	.20	.92
2014	.22	.27	.28	.18	.95
2015	.27	.26	.28	.22	1.03
2016	.31	*.24*	*.34*	*.26*	*1.15*
2017	*.35*	*.26*	*.36*	*.28*	*1.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.22	.22	.22	.22	.88
2013	.22	.22	.22	.22	.88
2014	.22	.22	.22	.22	.88
2015	.225	.225	.225	.225	.90
2016	.23				

BUSINESS: TECO Energy, Inc. is a holding company for Tampa Electric, which serves 706,000 customers in west central Florida, and Peoples Gas, which serves 354,000 customers in Florida. Acq'd New Mexico Gas (513,000 customers) 9/14. Sold TECO Transport 12/07; discontinued generation investments in Guatemala in '12; discontinued TECO Coal in '14. Electric revenue breakdown: residential, 50%; commercial, 30%; industrial, 8%; other, 12%. Generating sources: coal, 59%; gas, 36%; purchased, 5%. Fuel costs: 38% of revs. '14 reported deprec. rate (utility): 3.6%. Has 4,400 employees. Chairman: Sherrill W. Hudson. Pres. & CEO: John B. Ramil. Inc.: FL. Address: TECO Plaza, 702 N. Franklin St., Tampa, FL 33602. Tel.: 813-228-1111. Web: www.tecoenergy.com.

It appears as if the acquisition of TECO Energy might be completed within the next several weeks. Emera, a Canadian company, has agreed to pay $27.55 in cash for each share of TECO Energy. Just one more regulatory approval is required: that of the New Mexico Public Regulation Commission (NMPRC). The companies and various intervenors have reached an unopposed settlement that will be presented to the NMPRC. In early May, a hearing examiner conducted hearings on the proposed combination, and will make a recommendation by early June, before the NMPRC issues its ruling. The current time line suggests that July is the best estimate for the closing date of the transaction. Thus, this might well be our last full-page report on TECO Energy.

We advise TECO Energy stockholders to sell their shares on the open market. The recent price of TECO Energy stock is slightly *above* the buyout price, so stockholders have no incentive to await completion of the takeover. Emera's offer is generous, at 24 times estimated 2016 earnings. The Timeliness rank of TECO Energy stock remains suspended due to the pending acquisition.

TECO Energy's utilities are performing well. Tampa Electric and Peoples Gas are benefiting from healthy customer growth, thanks to the solid economy in the utilities' service territory, and each utility is likely to earn a return on equity in the upper half of its allowed ROE range in 2016. (The allowed ROEs are shown in Footnote E.) New Mexico Gas, which TECO Energy bought in September of 2014, is benefiting from effective cost controls. Because first-quarter results were better than we expected, we have raised our 2016 share-earnings estimate by a nickel, to $1.15. A continuation of current trends, plus rate relief that Tampa Electric will receive for a project to expand a gas-fired power plant, points to higher profits in 2017.

Our earnings presentation includes costs associated with the Emera deal. These were negligible in the first period of 2016, but reduced the bottom line by $0.06 a share in 2015. We are not estimating any such expenses over the remainder of 2016.

Paul E. Debbas, CFA *May 20, 2016*

(A) Diluted EPS. Excl. nonrec. gain (losses): '03, ($4.97); '07, 63¢; '10, (2¢); '14, (3¢); gains (losses) on disc. ops.: '04, (77¢); '05, 31¢; '06, 1¢; '07, 7¢; '12, (15¢); '14, (34¢); '15, (29¢). Next earnings report due early Aug. (B) Div'ds paid in late Feb., May, Aug., & Nov. ■ Div'd reinv. plan avail. (C) Incl. intangibles. In '15: $3.86/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '13 (elec.): 10.25%-12.25%; in '09 (gas): 9.75%-11.75%; in NM in '12: 10% (implied); earned on avg. com. eq., '15: 9.4%. Regulatory Climate: Avg.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	50
Earnings Predictability	80

UIL HOLDINGS NYSE-UIL

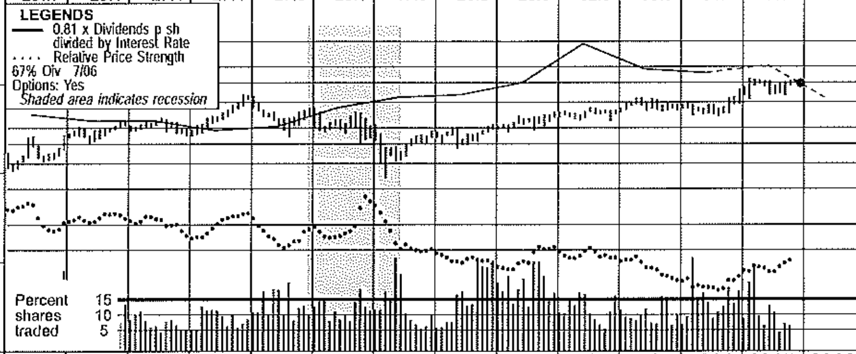
RECENT PRICE	49.75	P/E RATIO	21.1 (Trailing: 23.5, Median: 17.0)	RELATIVE P/E RATIO	1.19	DIV'D YLD	3.5%	VALUE LINE

TIMELINESS — Suspended 3/6/15
SAFETY 2 Raised 2/29/08
TECHNICAL — Suspended 3/6/15
BETA .75 (1.00 = Market)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:					32.8	33.7	43.8	43.0	37.8	31.2	31.3	35.8	37.7	42.1	46.3	52.5	
Low:					25.1	27.4	27.4	27.0	25.1	17.0	23.8	28.6	32.3	35.9	34.3	41.2	

Target Price Range 2018 | 2019 | 2020

LEGENDS
— 0.81 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
67% Div 7/06
Options: Yes
Shaded area indicates recession



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(Nil)	4%
Low	35	(-30%)	-4%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2014	1Q2015	2Q2015
to Buy	88	84	80
to Sell	104	115	96
Hld's(000)	38777	37867	41350

Percent shares traded 15 10 5

% TOT. RETURN 10/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	28.6	-1.3
3 yr.	60.5	49.3
5 yr.	122.9	73.5

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
29.01	37.54	46.15	47.55	40.39	45.87	49.88	34.03	39.23	37.69	29.91	19.75	31.01	29.22	28.52	28.70	*29.45*	*31.70*	Revenues per sh	*37.00*
4.67	5.53	6.61	5.89	4.69	4.37	4.13	4.65	5.48	5.93	5.09	3.65	5.33	5.65	5.51	4.64	*6.00*	*6.30*	"Cash Flow" per sh	*6.90*
2.23	2.56	2.53	1.85	1.24	1.54	1.30	1.86	1.87	1.89	1.94	1.99	1.96	2.04	2.28	1.92	*2.25*	*2.60*	Earnings per sh A	*2.75*
1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	*1.73*	*1.73*	Div'd Decl'd per sh B ■	*1.73*
1.48	2.31	2.01	2.41	2.19	2.04	2.25	3.09	9.92	8.57	4.12	4.03	6.48	5.67	5.38	5.49	*5.45*	*6.15*	Cap'l Spending per sh	*7.90*
19.55	20.42	21.25	20.28	20.65	22.84	22.39	18.53	18.55	18.85	19.15	21.31	21.61	21.95	23.85	24.07	*25.40*	*26.50*	Book Value per sh C	*30.45*
23.44	23.46	23.53	23.79	23.86	24.01	24.32	24.86	25.03	25.17	29.98	50.51	50.65	50.87	56.75	56.85	*56.75*	*56.75*	Common Shs Outst'g E	*56.75*
12.6	10.8	11.5	15.0	18.0	18.7	23.5	18.7	18.4	16.7	12.7	14.0	16.4	17.2	16.9	19.8	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.72	.70	.59	.82	1.03	.99	1.25	1.01	.98	1.01	.85	.89	1.03	1.09	.95	1.05	*Value Line*		Relative P/E Ratio	*1.00*
6.2%	6.2%	5.9%	6.2%	7.7%	6.0%	5.7%	5.0%	5.0%	5.5%	7.0%	6.2%	5.4%	4.9%	4.5%	4.6%	*estimates*		Avg Ann'l Div'd Yield	*3.9%*
						1213.1	846.0	982.0	948.7	896.6	997.7	1570.4	1486.5	1618.7	1631.9	*1670*	*1800*	Revenues ($mill)	*2100*
						31.4	45.4	46.7	48.1	54.3	70.3	99.7	103.7	120.3	109.6	*130*	*150*	Net Profit ($mill)	*170*
						44.1%	31.2%	39.5%	42.2%	38.0%	38.6%	38.5%	41.9%	37.7%	34.4%	*38.0%*	*38.0%*	Income Tax Rate	*40.0%*
						9.0%	8.0%	8.3%	8.3%	10.0%	26.3%	12.1%	--	12.1%	10.0%	*10.0%*	*10.0%*	AFUDC % to Net Profit	*10.0%*
						47.2%	47.0%	50.8%	53.6%	54.0%	58.4%	58.6%	58.9%	56.0%	55.6%	*58.0%*	*58.0%*	Long-Term Debt Ratio	*58.0%*
						52.8%	53.0%	49.2%	46.4%	46.0%	41.6%	41.4%	41.1%	44.0%	44.4%	*42.0%*	*42.0%*	Common Equity Ratio	*42.0%*
						1031.5	869.2	943.6	1023.6	1247.7	2587.9	2642.7	2716.9	3077.7	3079.6	*3430*	*3595*	Total Capital ($mill)	*4145*
						592.1	647.0	878.4	1073.6	1153.0	2327.5	2570.4	2787.4	3068.7	3292.7	*3380*	*3550*	Net Plant ($mill)	*4110*
						4.1%	6.5%	6.2%	6.1%	5.8%	3.7%	5.2%	5.4%	5.3%	5.0%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
						5.8%	9.9%	10.1%	10.1%	9.5%	6.5%	9.1%	9.3%	8.9%	8.0%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.0%*
						5.8%	9.9%	10.1%	10.1%	9.5%	6.5%	9.1%	9.3%	8.9%	8.0%	*10.0%*	*10.0%*	Return on Com Equity D	*10.0%*
						NMF	NMF	3.1%	1.0%	1.2%	1.7%	1.1%	1.5%	2.4%	.9%	*3.5%*	*4.0%*	Retained to Com Eq	*4.5%*
						NMF	117%	70%	90%	88%	74%	88%	84%	73%	89%	*65%*	*60%*	All Div'ds to Net Prof	*50%*

CAPITAL STRUCTURE as of 9/30/15
Total Debt $1821.8 mill. **Due in 5 Yrs.** $131.9 mill.
LT Debt $1730.3 mill. **LT Interest** $75.0 mill.
(LT interest earned: 3.0x)
Leases, Uncapitalized: Ann. rentals $4.5 mill.

Pension Assets-12/14 $722 mill. **Oblig.** $987 mill.

Pfd Stock None

Common Stock 56,629,377 shs.
as of 10/29/15

MARKET CAP: $2.7 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-2.6	-1.6	-1.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	7.1	7.8	7.9
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.2	+1.6	+.8
Fixed Charge Cov. (%)	249	262	257

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-4.5%	-4.0%	4.5%
"Cash Flow"	0.5%	-1.0%	4.5%
Earnings	3.0%	2.0%	5.0%
Dividends	--	--	Nil
Book Value	1.0%	4.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	458.3	283.5	323.8	420.9	1486.5
2013	548.0	319.1	316.5	435.1	1618.7
2014	571.2	334.8	293.0	432.9	1631.9
2015	584.1	312.0	330.5	*443.4*	*1670*
2016	*605*	*350*	*370*	*475*	*1800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.92	.23	.31	.56	2.04
2013	1.01	.35	.31	.61	2.28
2014	.97	.16	.22	.57	1.92
2015	1.01	.28	.27	*.69*	*2.25*
2016	*1.00*	*.40*	*.45*	*.75*	*2.60*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.432	.432	.432	.432	1.73
2012	.432	.432	.432	.432	1.73
2013	.432	.432	.432	.432	1.73
2014	.432	.432	.432	.432	1.73
2015	.432	.432			

BUSINESS: UIL Holdings, through its subsidiaries, operates as one of the largest regulated utility companies in Connecticut. Business consists of electric distribution/transmission operations of The United Illuminating Company and natural gas transportation/distribution operations of The Southern Connecticut Gas Company, The Connecticut Natural Gas Company, and The Berkshire Gas Company. Revenue distribution by class: residential, 53%; commercial, 28%; industrial, 4%; other, 15%. Fuel costs: 36% of revenues; O&M costs, 24%. Has 1,902 employees as of 12/14. President & Chief Executive Officer: James P. Torgerson. Inc.: CT. Address: 157 Church Street, P.O. Box 1564, New Haven, CT. 06506-0901. Telephone: 203-499-2000. Internet: www.uil.com.

UIL Holdings expects to soon become part of Iberdrola. Indeed, the Connecticut electric and gas utility is still targeting a year-end closing for its merger with the Spanish company's U.S. unit (Iberdrola U.S.), which includes New York State Electric & Gas and the second-largest wind-power portfolio in the United States. Under terms of the proposed transaction, investors are slated to receive $10.50 in cash and one share of newly issued stock in the merged company, worth up to $44.03, for each share of UIL that they own. Current UIL stakeholders would own 18.5% of the yet-to-be-named newco, which plans to list on the New York Stock Exchange, while Iberdrola S.A. would control the remaining 81.5%.

Left standing in the merger's way is, among other things, approval by the Connecticut Public Utility Regulatory Authority (CPURA). That body's draft decision in July would have denied the change of control, which prompted UIL to withdraw its original submission. A subsequent settlement agreement, promising concessions to ratepayers and other constituences, should help clear the path for approval. That said, CPURA is expected to issue a final ruling on December 9th.

Reported earnings rose sharply in the September quarter, as a one-time reserve made for an easy year-ago comparison. Still, the headline growth figure was significantly less than we envisioned, due to higher uncollectable billings at the utility's gas distribution unit. Ahead of the merger, UIL has also put off a rate case, further limiting near-term growth.

Shares of UIL remain unranked for year-ahead Timeliness due to the utility's pending merger with Iberdrola. Investors may want to stay pat here with the intention of participating in the cash-and-stock exchange. That option, in our view, will provide good exposure to what looks to be a relatively fast-growing, shareholder-friendly newco. Indeed, earnings at the merged company are expected to increase approximately 10% per year through 2019, partly reflecting the accelerated utilization of existing tax benefits. A competitive dividend and above-average payout increases also appear to be in the cards.

Nils C. Van Liew *November 20, 2015*

(A) EPS basic. Excl. nonrecur. gains (losses): '00, 4¢; '03, (26¢); '04, $2.14; '06, ($5.07); '10, (47¢). Next egs. report due in early February. (B) Div'ds historically paid in early March, June, Sept., and Dec. ■ Div'd reinvest. plan avail. (C) Incl. deferred charges. In '14: $321.9 mill. or $5.66/sh. (D) Rate base: orig. cost. Rate allowed on common equity in '13: 9.15%. Earned on average common equity in '14: 8.0%. Regul. Clim.: Below Average. (E) In millions. Adjusted for stock dividend.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	50
Earnings Predictability	85

UNS ENERGY NYSE-UNS

RECENT PRICE 60.41 | P/E RATIO 19.4 (Trailing: 19.2; Median: 18.0) | RELATIVE P/E RATIO 1.03 | DIV'D YLD 3.2% | VALUE LINE

TIMELINESS – Suspended 12/20/13
SAFETY 3 New 12/31/04
TECHNICAL – Suspended 12/20/13
BETA .75 (1.00 = Market)

High:	24.9	24.9	34.8	37.5	40.0	34.5	33.3	36.9	39.3	43.6	60.0	60.8
Low:	16.0	22.9	24.3	29.5	27.6	20.9	22.8	29.0	33.0	35.2	42.5	59.2

2017-19 PROJECTIONS

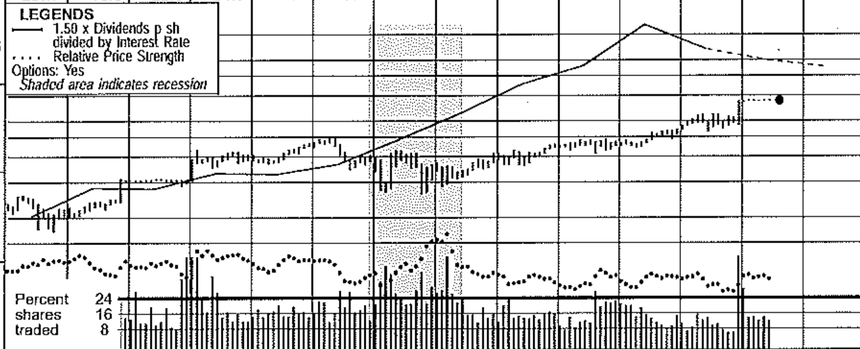
	Price	Gain	Ann'l Total Return
High	65	(+10%)	5%
Low	45	(-25%)	-3%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	1	0	0
to Sell	0	0	0	0	0	0	2	0	0

Institutional Decisions

	3Q2013	4Q2013	1Q2014
to Buy	109	96	74
to Sell	80	109	106
Hld's(000)	37570	38280	38587



Target Price Range
2017 | 2018 | 2019
128
96
80
64
48
40
32
24
16
12

% TOT. RETURN 6/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	39.5	25.1
3 yr.	82.1	52.6
5 yr.	179.8	168.7

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
23.83	24.85	31.12	43.12	25.50	28.71	34.13	35.26	37.42	39.12	39.41	38.89	39.78	40.89	35.36	35.74	*36.40*	*37.60*	Revenues per sh	*41.20*
3.48	3.96	4.23	5.41	4.80	5.20	5.29	5.21	5.68	5.64	4.56	7.82	7.33	7.44	6.48	7.33	*7.35*	*7.60*	"Cash Flow" per sh	*8.00*
.68	1.08	1.27	1.79	.97	1.30	1.31	1.30	1.85	1.55	.39	2.69	2.82	2.75	2.20	3.04	*3.12*	*3.40*	Earnings per sh A	*3.80*
--	--	.32	.40	.50	.60	.64	.76	.84	.90	.96	1.16	1.56	1.68	1.72	1.74	*1.85*	*1.95*	Div'd Decl'd per sh B ■ †	*2.28*
2.52	2.87	3.19	3.63	3.36	4.06	4.49	5.83	6.77	6.95	9.85	8.01	7.26	10.13	7.43	7.85	*9.45*	*8.05*	Cap'l Spending per sh	*7.85*
7.65	10.02	11.20	12.68	13.05	15.97	16.95	17.68	18.59	19.54	19.16	20.94	22.46	24.07	25.77	27.22	*27.00*	*28.20*	Book Value per sh	*32.70*
32.26	32.35	33.22	33.50	33.58	33.79	34.26	34.87	35.19	35.32	35.46	35.85	36.54	36.92	41.34	41.54	*41.50*	*42.00*	Common Shs Outst'g C	*42.50*
23.3	10.8	11.8	10.8	18.2	14.6	18.7	23.9	17.7	22.0	NMF	10.4	11.6	13.3	17.8	15.9	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
1.21	.62	.77	.55	.99	.83	.99	1.27	.96	1.17	NMF	.69	.74	.83	1.13	.89	*Value Line*		Relative P/E Ratio	*.90*
--	--	2.1%	2.1%	2.8%	3.2%	2.6%	2.5%	2.6%	2.6%	3.3%	4.1%	4.8%	4.6%	4.4%	3.6%	*estimates*		Avg Ann'l Div'd Yield	*4.1%*

CAPITAL STRUCTURE as of 12/31/13
Total Debt $1806.6 mill. Due in 5 Yrs $477.0 mill.
LT Debt $1733.3 mill. LT Interest $71.0 mill.
Incl. $73.9 mill. capitalized leases.

(LT interest earned: 3.0x)

Pension Assets-12/13 $323 mill. Oblig. $352 mill.
Pfd Stock None

Common Stock 41,701,718 shs.
as of 4/17/14
MARKET CAP: $2.5 billion (Mid Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
1169.0	1229.5	1316.9	1381.4	1397.5	1394.4	1453.7	1509.5	1461.8	1484.6	*1510*	*1580*	Revenues ($mill)	*1750*
45.9	46.1	69.2	58.4	14.0	104.3	111.5	110.0	90.9	127.5	*125*	*140*	Net Profit ($mill)	*160*
42.5%	41.4%	38.8%	40.1%	54.8%	38.2%	41.2%	37.8%	38.0%	31.4%	*38.0%*	*38.0%*	Income Tax Rate	*40.0%*
--	--	2.9%	3.4%	--	--	--	--	--	--	*Nil*	*Nil*	AFUDC % to Net Profit	*Nil*
77.1%	75.3%	72.9%	68.8%	72.9%	70.5%	68.5%	67.8%	62.3%	59.4%	*62.0%*	*62.5%*	Long-Term Debt Ratio	*63.0%*
22.9%	24.7%	27.1%	31.2%	27.1%	29.5%	31.5%	32.2%	37.7%	40.6%	*38.0%*	*37.5%*	Common Equity Ratio	*37.0%*
2540.3	2494.9	2414.1	2214.9	2506.4	2547.0	2602.8	2758.6	2826.0	2787.6	*2950*	*3180*	Total Capital ($mill)	*3740*
2081.1	2171.5	2259.6	2407.3	2617.7	2785.7	2961.5	3182.3	3300.4	3534.8	*3450*	*3625*	Net Plant ($mill)	*4200*
5.1%	5.1%	5.9%	5.7%	3.0%	5.2%	5.5%	5.3%	4.5%	5.8%	*6.0%*	*6.0%*	Return on Total Cap'l	*5.5%*
7.9%	7.5%	10.6%	8.5%	2.1%	13.9%	13.6%	12.4%	8.5%	11.3%	*11.0%*	*12.0%*	Return on Shr. Equity	*11.5%*
7.9%	7.5%	10.6%	8.5%	2.1%	13.9%	13.6%	12.4%	8.5%	11.3%	*11.0%*	*12.0%*	Return on Com Equity D	*11.5%*
4.1%	3.2%	6.1%	3.9%	NMF	8.4%	6.7%	5.4%	2.0%	4.9%	*4.5%*	*5.5%*	Retained to Com Eq	*4.5%*
48%	57%	43%	54%	NMF	40%	51%	56%	77%	57%	*58%*	*53%*	All Div'ds to Net Prof	*60 %*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+.4	-.7	+.1
Avg. Indust. Use (MWH)	5060	5086	5090
Avg. Indust. Revs. per KWH (¢)	7.10	7.20	7.20
Capacity at Peak (Mw)	3271	2950	3015
Peak Load, Summer (Mw)	2334	2290	2230
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	+.4	+.5	+.8
Fixed Charge Cov. (%)	251	239	291

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	1.5%	-0.5%	*1.5%*
"Cash Flow"	3.5%	6.0%	*2.0%*
Earnings	7.0%	16.0%	*6.0%*
Dividends	13.0%	13.5%	*5.0%*
Book Value	6.5%	6.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	344.8	369.7	450.9	344.1	1509.5
2012	315.4	364.0	434.1	348.3	1461.8
2013	332.1	365.2	437.0	350.2	1484.6
2014	333.4	*370*	*450*	*356.6*	*1510*
2015	*350*	*375*	*485*	*370*	*1580*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.35	.71	1.46	.22	2.75
2012	.17	.64	1.21	.18	2.20
2013	.27	.83	1.62	.32	3.04
2014	.37	*.75*	*1.67*	*.33*	*3.12*
2015	*.45*	*.80*	*1.65*	*.50*	*3.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.39	.39	.39	.39	1.56
2011	.42	.42	.42	.42	1.68
2012	.43	.43	.43	.43	1.72
2013	.435	.435	.435	.435	1.74
2014	.48	.48			

BUSINESS: UNS Energy Corporation, through its subsidiaries, operates as an electric utility in Arizona. Subsidiaries include Tucson Electric Power (TEP), UNS Gas, and UNS Electric. '13 retail customers: TEP, 413,000 (in southeastern Arizona); UNS Gas, 149,000; UNS Electric, 93,000. Revenue sources: residential, 42%; commercial, 23%; industrial, 35%. Copper mining is largest industry served. Fuels: coal, 75%; gas, 8%; purchased power, 17%. '13 TEP reported depreciation rate: 4.0%. Has 1,977 employees: TEP, 1,398; UNS Gas, 188; UNS Electric, 143; Other, 248. Chrmn. & CEO: David G. Hutchens. Inc.: AZ. Address: 88 E. Broadway Blvd., Tucson, AZ 85701. Telephone: 520-571-4000. Internet: www.uns.com.

The acquisition of UNS Energy by Canada-based Fortis Inc. moves closer toward completion. Fortis would pay $60.25 in cash for each UNS share. Indeed, the purchase seems to be moving to culmination at a reasonable pace since the takeover announcement in December, 2013. Most recently, UNS Energy and Fortis filed a settlement agreement with Arizona Corporation Commission (ACC) on May 16th, related to the intended acquisition. As part of the settlement, UNS Energy and Fortis have agreed to provide customer-bill credits amounting to $30 million over a period of five years. Upon completion of the deal, clients of Tucson Electric Power (TEP) and UniSource Energy Services (UES) are expected to get bill credits equaling $10 million in the first year and $5 million a year over the remaining four years. Fortis is also expected to strengthen UNS Energy's balance sheet by $220 million from the originally-agreed amount of $200 million. If approved, the settlement is set to be completed by September.

The takeover is expected to be finalized by the end of 2014. The $4.3 billion transaction, in which Fortis will assume $1.8 billion in debt and UNS equity of $2.5 billion, was approved by shareholders on March 26th. It was followed by the approval of the Federal Energy Regulatory Commission and that of the Commission on Foreign Investment. A green light from the ACC is one of the last regulatory hurdles remaining.

The deal should give UNS Energy and its subsidiaries access to new resources and capital. As per Arizona's renewable energy standard, utilities are expected to reduce reliance on coal and natural gas for energy generation, and increase their use of renewable energy to 15% by 2025. Significant investments will be required toward this move.

We have suspended the Timeliness rank for this issue due to the impending acquisition. This stock is currently trading above the deal price. We suggest investors sell their holdings at the present level, as there is not much room for capital gains right now. Moreover, selling at the current price will eliminate any downside risk, in case the transaction falls through.

Saumya Ajila *August 1, 2014*

(A) EPS diluted. Excl. nonrecur. gains: '98, 19¢; '99, $1.35; '00, 48¢; '03, $2.00. Next earnings report due early November. Earnings may not sum due to rounding. (B) Div'ds historically paid in Mar., June, Sept., and Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) In millions. (D) Rate base: fair value. Rate allowed on com. eq. in '13: 10.0%; earned on avg. com. eq., '13: 8.5%. Regulatory Climate: Avg.

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	80
Earnings Predictability	40

VECTREN CORP. NYSE-VVC

RECENT PRICE 56.30 | P/E RATIO 21.2 (Trailing: 22.1; Median: 16.0) | RELATIVE P/E RATIO 1.09 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 3 Lowered 7/22/16

SAFETY 2 Lowered 1/5/01

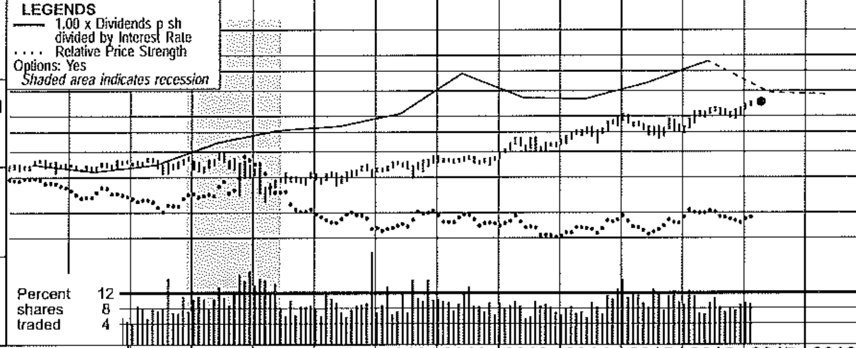
TECHNICAL 3 Raised 2/24/17

BETA .75 (1.00 = Market)

High:	29.3	30.5	32.2	26.9	27.8	30.7	30.8	37.9	48.3	49.5	53.3	57.1
Low:	25.2	24.8	19.5	18.1	21.7	23.7	27.5	29.5	34.6	37.3	39.4	51.5

Target Price Range 2020 | 2021 | 2022

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+15%)	7%
Low	45	(-20%)	-1%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	10
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2016	3Q2016	4Q2016
to Buy	151	129	138
to Sell	112	136	132
Hld's(000)	52315	51679	52408

Percent shares traded 12 8 4

% TOT. RETURN 2/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	27.9	30.5
3 yr.	62.6	22.1
5 yr.	133.6	81.5

Vectren was formed on March 31, 2000 through the merger of Indiana Energy and SIGCORP. The merger was consummated with a tax-free exchange of shares and has been accounted for as a pooling of interests. Indiana Energy common stockholders received one Vectren common share for each share held. SIGCORP stockholders exchanged each common share for 1.333 common shares of Vectren.

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
29.88	30.67	25.76	26.06	28.39	27.16	30.23	31.62	29.40	29.53	*30.85*	*31.90*	Revenues per sh	*40.70*
4.29	3.97	4.40	4.44	4.71	5.03	5.03	5.33	5.48	5.69	*5.95*	*6.25*	"Cash Flow" per sh	*7.80*
1.83	1.63	1.79	1.65	1.73	1.94	1.66	2.02	2.39	2.55	*2.70*	*2.85*	Earnings per sh A	*3.45*
1.27	1.31	1.35	1.37	1.39	1.41	1.43	1.46	1.54	1.62	*1.70*	*1.78*	Div'd Decl'd per sh B■†	*2.00*
4.38	4.83	5.33	3.39	3.92	4.45	4.77	5.43	5.76	6.54	*6.95*	*7.40*	Cap'l Spending per sh	*8.70*
16.16	16.68	17.23	17.61	17.89	18.57	18.86	19.45	20.34	21.33	*22.50*	*23.80*	Book Value per sh C	*27.05*
76.36	81.03	81.10	81.70	81.90	82.20	82.40	82.60	82.80	82.90	*83.50*	*84.00*	Common Shs Outst'g D	*86.00*
15.3	16.8	12.9	15.0	15.8	15.0	20.7	20.0	17.9	19.2	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*16.0*
.81	1.01	.86	.95	.99	.95	1.16	1.05	.90	1.01	*estimates*		Relative P/E Ratio	*1.00*
4.5%	4.8%	5.9%	5.5%	5.1%	4.8%	4.2%	3.6%	3.6%	3.3%			Avg Ann'l Div'd Yield	*3.6%*
2281.9	2484.7	2088.9	2129.5	2325.2	2232.8	2491.2	2611.7	2434.7	2448.3	*2575*	*2680*	Revenues ($mill)	*3500*
143.1	129.0	145.0	133.7	141.6	159.0	136.6	166.9	197.3	211.6	*225*	*240*	Net Profit ($mill)	*295*
34.7%	37.1%	26.5%	35.8%	37.9%	34.2%	32.9%	32.7%	33.6%	34.8%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
2.8%	2.9%	4.1%	--	--	--	--	--	4.1%	4.0%	*4.0%*	*4.0%*	AFUDC % to Net Profit	*4.0%*
50.2%	48.0%	52.4%	49.9%	51.6%	50.4%	53.3%	46.7%	50.6%	47.3%	*48.0%*	*48.0%*	Long-Term Debt Ratio	*48.0%*
49.8%	52.0%	47.6%	50.1%	48.4%	49.6%	46.7%	53.3%	49.4%	52.7%	*52.0%*	*52.0%*	Common Equity Ratio	*52.0%*
2479.1	2599.5	2937.7	2874.1	3025.1	3079.5	3331.4	3013.9	3406.6	3358.0	*3630*	*3850*	Total Capital ($mill)	*4475*
2539.7	2720.3	2878.8	2955.4	3032.6	3119.6	3224.3	3439.0	4089.5	4406.8	*4700*	*5000*	Net Plant ($mill)	*6000*
7.2%	6.5%	6.3%	6.1%	6.2%	6.4%	5.4%	6.8%	7.0%	7.4%	*7.5%*	*7.5%*	Return on Total Cap'l	*7.5%*
11.6%	9.5%	10.4%	9.3%	9.7%	10.4%	8.8%	10.4%	11.7%	12.0%	*12.0%*	*12.0%*	Return on Shr. Equity	*12.5%*
11.6%	9.5%	10.4%	9.3%	9.7%	10.4%	8.8%	10.4%	11.7%	12.0%	*12.0%*	*12.0%*	Return on Com Equity E	*12.5%*
3.8%	2.0%	2.6%	1.6%	1.9%	2.9%	1.2%	2.9%	4.2%	4.4%	*4.5%*	*4.5%*	Retained to Com Eq	*5.5%*
67%	80%	75%	83%	80%	73%	86%	72%	65%	63%	*63%*	*62%*	All Div'ds to Net Prof	*58%*

CAPITAL STRUCTURE as of 12/31/16
Total Debt $1908.4 mill. Due in 5 Yrs $633.5 mill.
LT Debt $1589.9 mill. LT Interest $85.0 mill.
(LT interest earned: 4.8x)

Pension Assets-12/16 $304.5 mill. Oblig. $350.4 mill.

Pfd Stock None

Common Stock 82,922,412 shs. as of 1/31/17

MARKET CAP: $4.7 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+2.0	-2.4	+.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	1407	1357	1360
Peak Load, Summer (Mw)	1095	1088	1096
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.6	+.7	+.8
Fixed Charge Cov. (%)	363	428	446

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	2.0%	2.5%	5.0%
"Cash Flow"	4.5%	4.0%	6.0%
Earnings	4.0%	6.0%	7.0%
Dividends	2.5%	2.5%	4.5%
Book Value	3.0%	3.0%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) F Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2014	796.8	542.5	595.6	676.8	2611.7
2015	706.2	551.0	573.5	604.0	2434.7
2016	584.8	533.7	631.0	699.0	2448.3
2017	*660*	*565*	*650*	*700*	*2575*
2018	*680*	*600*	*675*	*725*	*2680*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2014	.62	.14	.57	.69	2.02
2015	.69	.43	.48	.79	2.39
2016	.58	.39	.74	.84	2.55
2017	*.64*	*.43*	*.75*	*.88*	*2.70*
2018	*.70*	*.46*	*.78*	*.91*	*2.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.355	.355	.355	.360	1.43
2014	.360	.360	.360	.380	1.46
2015	.380	.380	.380	.400	1.54
2016	.400	.400	.400	.420	1.62
2017	.420				

BUSINESS: Vectren is a holding company formed through the merger of Indiana Energy and SIGCORP. Supplies electricity and gas to an area nearly two-thirds of the state of Indiana. Owns gas distribution assets in Ohio. Has a customer base exceeding 1.1 million. 2016 Electricity revenues: residential, 37%; commercial, 27%; industrial, 34%; other, 2%. 2016 Gas revenues: residential, 67%; commercial, 23%; other, 10%. Nonutility operations include Infrastructure Services and Energy Services. Est'd plant age: electric, 10 years. '16 depreciation rate: 4.0%. Has about 5,800 employees. Chairman, President, & CEO: Carl Chapman. Incorporated: Indiana. Address: One Vectren Square, Evansville, Indiana 47708. Telephone: 812-491-4000. Internet: www.vectren.com.

Shares of Vectren have moved higher in price in recent months, and are presently trading close to an all-time high. The company finished 2016 on a good note. Revenues advanced nearly 16% in the December quarter, on a year-to-year basis. Expenses increased at roughly the same pace, and share earnings were moderately higher. Favorable performance at the Utility Group was largely driven by continued investment in gas infrastructure programs in both Indiana and Ohio. On the nonutility side, the Infrastructure Services distribution business was able to capitalize on greater spending on gas infrastructure systems. Performance at the Infrastructure Services transmission operation has been impacted by increasing competition, which has reduced the number of projects awarded and pressured margins. The recent addition of several projects has provided some support here, and should continue to do so.

Overall performance should remain solid going forward. Continued investment by the company in gas infrastructure and accelerated spending in its electric system augur well for future performance here. Vectren's utility businesses remain well positioned in their service territories. We look for solid results at the company's nonutility operations, as well. A greater national emphasis on infrastructure spending in the coming years may well benefit performance at the Infrastructure Services line. We envision healthy growth at the Energy Services unit, too.

These shares do not stand out at this time. The stock is ranked to mirror the broader market for the year ahead. Long-term total return potential is nothing to write home about, either. This issue presently trades at a price-to-earnings multiple that is well above its historical average, following a run-up in the share price. We do expect solid growth at the company out to early next decade, but this appears to be discounted by the recent quotation. A selloff some time down the road may offer conservative, income-seeking accounts a more attractive entry point. Vectren earns good marks for Safety, Financial Strength, Price Stability, and Earnings Predictability. Volatility is below average here, as well (Beta: .75).

Michael Napoli, CFA *March 17, 2017*

(A) Diluted EPS. Excl. nonrecur. gain (loss): '09, 15¢. Next egs report due early May. (B) Div'ds historically paid in early March, June, September, and December. ■Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '16, $7.27/sh. (D) In millions. (E) Electric rate base determination: fair value. Rates allowed on elect. common equity range from 10.15% to 10.4%. Regulatory Climate: Above Average. (F) Totals may not sum due to rounding.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	75

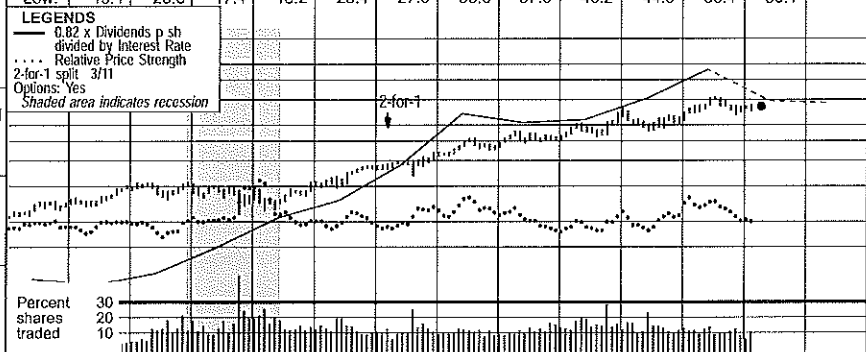
WEC ENERGY GROUP NYSE-WEC

RECENT PRICE 59.29 | P/E RATIO 19.4 (Trailing: 20.1 Median: 16.0) | RELATIVE P/E RATIO 0.99 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 3 Lowered 9/16/16
SAFETY 1 Raised 3/23/12
TECHNICAL 3 Raised 1/20/17
BETA .60 (1.00 = Market)

High:	24.3	25.2	24.8	25.3	30.5	35.4	41.5	45.0	55.4	58.0	66.1	60.7	
Low:	19.1	20.5	17.4	18.2	23.4	27.0	33.6	37.0	40.2	44.9	50.4	56.1	

Target Price Range 2020 | 2021 | 2022



128 96 80 64 48 40 32 24 16 12

2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+10%)	6%
Low	55	(-5%)	2%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	5	2	0	5	0	0	0	0	24
to Sell	4	2	0	6	0	0	0	0	1

Institutional Decisions

	2Q2016	3Q2016	4Q2016
to Buy	334	278	325
to Sell	235	299	272
Hld's(000)	223080	214898	223988

Percent shares traded 30 20 10

% TOT. RETURN 2/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	10.6	30.5
3 yr.	51.4	22.1
5 yr.	108.9	81.5

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
17.02	16.10	17.12	14.66	16.31	17.08	18.12	18.95	17.65	17.98	19.46	18.54	20.00	22.16	18.77	23.68	24.25	25.20	Revenues per sh	28.25
2.72	2.84	2.86	2.58	2.89	2.90	2.98	2.95	3.11	3.30	3.68	4.01	4.33	4.47	3.87	5.39	5.60	5.85	"Cash Flow" per sh	6.75
.92	1.16	1.13	.93	1.28	1.32	1.42	1.52	1.60	1.92	2.18	2.35	2.51	2.59	2.34	2.96	3.10	3.25	Earnings per sh A	3.75
.40	.40	.40	.42	.44	.46	.50	.54	.68	.80	1.04	1.20	1.45	1.56	1.74	1.98	2.08	2.18	Div'd Decl'd per sh B ■	2.50
3.01	2.54	2.95	2.85	3.40	4.17	5.28	4.86	3.50	3.41	3.60	3.09	3.04	3.26	4.01	4.51	7.00	6.30	Cap'l Spending per sh	5.75
8.91	9.22	9.96	10.65	11.46	12.35	13.25	14.27	15.26	16.26	17.20	18.05	18.73	19.60	27.42	28.29	29.30	30.30	Book Value per sh C	33.75
230.84	232.06	236.85	233.97	233.96	233.94	233.89	233.84	233.82	233.77	230.49	229.04	225.96	225.52	315.68	315.62	315.65	315.65	Common Shs Outst'g D	315.65
12.1	10.5	12.4	17.5	14.5	16.0	16.5	14.8	13.3	14.0	14.2	15.8	16.5	17.7	21.3	19.9	Bold figures are		Avg Ann'l P/E Ratio	16.0
.62	.57	.71	.92	.77	.86	.88	.89	.89	.89	.89	1.01	.93	.93	1.07	1.05	Value Line		Relative P/E Ratio	1.00
3.6%	3.3%	2.8%	2.6%	2.4%	2.2%	2.1%	2.4%	3.2%	3.0%	3.3%	3.2%	3.5%	3.4%	3.5%	3.4%	estimates		Avg Ann'l Div'd Yield	4.2%

CAPITAL STRUCTURE as of 12/31/16
Total Debt $10176 mill. Due in 5 Yrs $3250.8 mill.
LT Debt $9158.2 mill. LT Interest $462.5 mill.
Incl. $29.6 mill. capitalized leases.
(LT interest earned: 4.7x)
Leases, Uncapitalized Annual rentals $9.9 mill.
Pension Assets-12/16 $2709.2 mill. Oblig $3058.8 mill.
Pfd Stock $30.4 mill. Pfd Div'd $1.2 mill.
260,000 shs. 3.60%, $100 par, callable. $101;
44,498 shs. 6%, $100 par.
Common Stock 315,587,523 shs.
as of 1/31/17
MARKET CAP: $19 billion (Large Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
4237.8	4431.0	4127.9	4202.5	4486.4	4246.4	4519.0	4997.1	5926.1	7472.3	7650	7950	Revenues ($mill)	8900
337.7	359.8	378.4	455.6	514.0	547.5	578.6	589.5	640.3	940.2	980	1025	Net Profit ($mill)	1180
39.1%	37.6%	36.5%	35.4%	33.9%	35.9%	36.9%	38.0%	40.4%	37.6%	37.5%	37.5%	Income Tax Rate	38.0%
23.8%	27.2%	25.0%	18.6%	16.8%	9.4%	4.5%	1.3%	4.5%	3.8%	4.0%	3.0%	AFUDC % to Net Profit	3.0%
50.3%	54.8%	51.9%	50.6%	53.6%	51.7%	50.6%	48.5%	51.2%	50.5%	49.5%	50.5%	Long-Term Debt Ratio	48.5%
49.2%	44.8%	47.7%	49.0%	46.0%	48.0%	49.1%	51.2%	48.6%	49.3%	50.0%	49.5%	Common Equity Ratio	51.0%
6302.1	7442.0	7473.1	7764.5	8608.0	8619.3	8626.6	8636.5	17809	18118	18425	19400	Total Capital ($mill)	20775
7681.2	8517.0	9070.5	9601.5	10160	10572	10907	11258	19190	19916	21350	22500	Net Plant ($mill)	25550
7.0%	6.3%	6.4%	7.5%	7.5%	7.9%	8.1%	8.1%	4.5%	6.3%	6.5%	6.5%	Return on Total Cap'l	7.0%
10.8%	10.7%	10.5%	11.9%	12.9%	13.1%	13.6%	13.2%	7.4%	10.5%	10.5%	10.5%	Return on Shr. Equity	11.0%
10.9%	10.7%	10.6%	12.0%	12.9%	13.2%	13.6%	13.3%	7.4%	10.5%	10.5%	10.5%	Return on Com Equity E	11.0%
7.1%	7.0%	6.2%	7.0%	6.8%	6.5%	5.9%	5.3%	2.1%	3.5%	3.5%	3.5%	Retained to Com Eq	3.5%
35%	35%	42%	41%	47%	51%	57%	60%	71%	67%	67%	67%	All Div'ds to Net Prof	67%

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	-5.9	+29.1	+18.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Lg. C&I Revs. per KWH (¢)	8.62	7.71	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.5	+40.2	NA
Fixed Charge Cov. (%)	454	364	404

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	3.0%	3.0%	4.5%
"Cash Flow"	5.0%	6.5%	6.5%
Earnings	8.5%	6.5%	6.0%
Dividends	15.0%	16.0%	6.0%
Book Value	8.0%	9.0%	5.0%

QUARTERLY REVENUES ($ mill.)

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	1695	1044	1033	1225	4997.1
2015	1388	991	1699	1848	5926.1
2016	2195	1602	1712	1963	7472.3
2017	2300	1650	1700	2000	7650
2018	2400	1700	1750	2100	7950

EARNINGS PER SHARE A

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.91	.58	.56	.53	2.59
2015	.86	.35	.58	.57	2.34
2016	1.09	.57	.68	.61	2.96
2017	1.05	.65	.75	.65	3.10
2018	1.10	.67	.80	.68	3.25

QUARTERLY DIVIDENDS PAID B ■

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.34	.34	.382	.383	1.45
2014	.39	.39	.39	.39	1.56
2015	.422	.422	.44	.457	1.74
2016	.495	.495	.495	.495	1.98
2017	.52				

BUSINESS: WEC Energy Group, Inc. (formerly Wisconsin Energy) is a holding company for utilities that provide electric, gas & steam service in WI & gas service in IL, MN, & MI. Customers: 1.6 mill. elec., 2.8 mill. gas. Acq'd Integrys Energy 6/15. Sold Point Beach nuclear plant in '07. Elec. rev. breakdown: residential, 35%; small commercial & industrial, 31%; large commercial & industrial, 21%; other, 13%. Generating sources: coal, 52%; gas, 16%; renewables, 3%; purchased, 29%. Fuel costs: 35% of revs. '16 reported deprec. rates (utility): 2.3%-3.3%. Has 8,200 employees. Chairman: Gale E. Klappa. President & CEO: Allen L. Leverett. Inc.: Wisconsin. Address: 231 W. Michigan St., P.O. Box 1331, Milwaukee, WI 53201. Tel.: 414-221-2345. Internet: www.wecenergygroup.com.

WEC Energy Group's board of directors has raised the dividend. As is the practice in recent years, in early December WEC announced its expectation of a boost in the disbursement, and the board followed through at its meeting in January. The increase was $0.10 a share (5.1%) annually. The company's goals for its dividend are an annual growth rate of 5%-7% (matching its target for earnings growth) and a payout ratio of 65%-70%.

We estimate that WEC's earnings will advance 5% in 2017 and 2018. The company's Peoples Gas subsidiary in Chicago benefits from its accelerated main replacement program, in which the utility receives a current return (via a monthly charge on customers' bills) for the $280 million-$300 million it spends yearly on this program. Our 2017 share-net estimate is within management's targeted range of $3.06-$3.12 a share.

WEC's electric utility in Michigan has asked the state commission for a certificate of need to build a gas-fired plant. The 180-megawatt facility would cost an estimated $275 million and would be completed in 2019. Half of the plant's costs would be recovered in rates, the other half from a large industrial customer through a 20-year contract. After the project is completed, the utility would retire an aging coal-fired plant. A ruling from the Michigan regulators is expected by October.

The company has announced a gas storage acquisition. WEC has agreed to pay $230 million in cash for a gas storage facility in Michigan. The utility is asking the state commission for a declaratory ruling approving the deal. This would provide a return on investment similar to that of a utility.

Finances are strong. WEC's fixed-charge coverage is well above the industry average. The common-equity ratio is healthy. The earned return on equity isn't as high as it was before the Integrys takeover in 2015, but is still adequate.

WEC stock offers a dividend yield that is average for a utility. Conservative accounts might find this suitable, given the equity's top-notch Safety rank. Like most issues in this industry, however, 3- to 5-year total return potential is just modest.

Paul E. Debbas, CFA *March 17, 2017*

(A) Diluted EPS. Excl. gains on disc. ops.: '04, 77¢; '05, 2¢; '06, 2¢; '09, 2¢; '10, 1¢; '11, 6¢. '14-'16 EPS don't sum due to rounding or chng. in shs. Next egs. report due early May. (B) Div'ds paid in early Mar., June, Sept. & Dec. ■ Div'd reinv. avail. (C) Incl. intang. In '16: $19.44/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rates all'd on com. eq. in WI in '15: 10.0%-10.3%; in IL in '15: 9.05%; in MN in '16: 9.11%; in MI in '16: 9.9%; earned on avg. com. eq., '16: 10.6%. Regul. Climate: WI, Above Avg.; IL, Below Avg.; MN & MI, Avg.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	85
Earnings Predictability	85

WESTAR ENERGY NYSE-WR

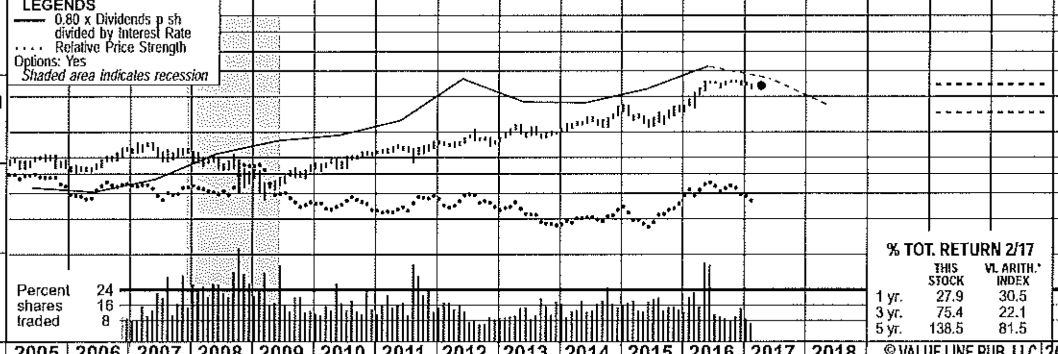
RECENT PRICE	P/E RATIO	(Trailing / Median)	RELATIVE P/E RATIO	DIV'D YLD	
54.48	21.9	(Trailing: 22.4, Median: 15.0)	1.12	2.9%	VALUE LINE

TIMELINESS – Suspended 6/10/16
SAFETY 2 Raised 4/1/05
TECHNICAL – Suspended 6/10/16
BETA .70 (1.00 = Market)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
High:	27.2	28.6	25.9	22.3	25.9	29.0	33.0	35.0	43.2	44.0	57.5
Low:	20.1	22.8	16.0	14.9	20.6	22.6	26.8	28.6	31.7	33.9	40.0

High:	27.2	28.6	25.9	22.3	25.9	29.0	33.0	35.0	43.2	44.0	57.5	56.6
Low:	20.1	22.8	16.0	14.9	20.6	22.6	26.8	28.6	31.7	33.9	40.0	52.2

Target Price Range 2020 | 2021 | 2022



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(Nil)	4%
Low	40	(-25%)	-3%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	16
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2016	3Q2016	4Q2016
to Buy	218	160	182
to Sell	174	185	173
Hld's(000)	99811	100465	101542

% TOT. RETURN 2/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	27.9	30.5
3 yr.	75.4	22.1
5 yr.	138.5	81.5

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
31.20	24.77	20.06	17.02	18.23	18.37	18.09	16.98	17.04	18.34	17.27	17.88	18.48	19.76	17.40	18.07	*18.35*	*18.30*	Revenues per sh	*18.90*
5.32	4.77	3.77	3.12	3.28	3.94	3.77	3.14	3.59	4.24	3.97	4.30	4.41	4.55	4.26	4.83	*4.95*	*5.05*	"Cash Flow" per sh	*5.65*
d.58	1.00	1.48	1.17	1.55	1.88	1.84	1.31	1.28	1.80	1.79	2.15	2.27	2.35	2.09	2.43	*2.55*	*2.60*	Earnings per sh A	*3.15*
1.20	1.20	.87	.80	.92	.98	1.08	1.16	1.20	1.24	1.28	1.32	1.36	1.40	1.44	1.52	*1.60*	*1.68*	Div'd Decl'd per sh B■†	*1.92*
3.37	1.89	2.06	2.19	2.45	3.95	7.84	8.65	5.26	4.82	5.55	6.40	6.08	6.47	4.95	7.67	*5.50*	*6.25*	Cap'l Spending per sh	*7.00*
25.97	13.68	14.23	16.13	16.31	17.62	19.14	20.18	20.59	21.25	22.03	22.89	23.88	25.02	25.87	27.03	*27.40*	*27.50*	Book Value per sh C	*28.75*
70.08	71.51	72.84	86.03	86.84	87.39	95.46	108.31	109.07	112.13	125.70	126.50	128.25	131.69	141.35	141.79	*146.00*	*149.00*	Common Shs Outst'g E	*160.00*
--	14.0	10.8	17.4	14.8	12.2	14.1	17.0	14.9	13.0	14.8	13.4	14.0	15.4	18.5	21.6	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
--	.76	.62	.92	.79	.66	.75	1.02	.99	.83	.93	.85	.79	.81	.94	1.09	*Value Line*		Relative P/E Ratio	*.95*
5.8%	8.6%	5.5%	3.9%	4.0%	4.3%	4.2%	5.2%	6.3%	5.3%	4.8%	4.6%	4.3%	3.9%	3.7%	2.9%	*estimates*		Avg Ann'l Div'd Yield	*4.1%*

CAPITAL STRUCTURE as of 12/31/16
Total Debt $3755.4 mill. **Due in 5 Yrs** $800 mill.
LT Debt $3388.7 mill. **LT Interest** $145.0 mill.
(LT interest earned: 4.2x)

Pension Assets 12/16 $658 mill. **Oblig.** $1.0 bill.

Pfd Stock None

Common Stock 141,791,153 shs.
MARKET CAP: $7.7 billion (Large Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
1726.8	1839.0	1858.2	2056.2	2171.0	2261.5	2370.7	2601.7	2459.2	2562.1	*2680*	*2730*	Revenues ($mill)	*3020*
168.4	136.8	141.3	203.9	214.0	275.1	292.5	313.3	291.9	346.6	*375*	*390*	Net Profit ($mill)	*505*
27.5%	24.8%	29.4%	29.0%	35.2%	30.9%	33.1%	31.9%	33.5%	33.8%	*34.0%*	*34.0%*	Income Tax Rate	*34.0%*
10.4%	--	--	--	--	--	--	--	10.4%	*10.0%*	*10.0%*	*10.0%*	AFUDC % to Net Profit	*10.0%*
50.6%	49.8%	53.4%	53.6%	49.5%	51.2%	50.0%	50.0%	47.5%	*51.0%*	*50.0%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
48.9%	49.7%	46.1%	46.0%	50.1%	48.8%	50.0%	50.0%	52.5%	*49.0%*	*50.0%*	*50.0%*	Common Equity Ratio	*50.0%*
3738.3	4400.1	4866.8	5180.9	5531.0	5938.2	6131.1	6596.2	6958.8	*6900*	*7200*	*7300*	Total Capital ($mill)	*7700*
4803.7	5533.5	5771.7	6309.5	6745.4	7335.7	7848.5	8441.5	8793.1	9506.3	*9750*	*9900*	Net Plant ($mill)	*10500*
5.8%	4.2%	4.4%	5.5%	5.3%	6.0%	6.1%	6.0%	5.3%	*5.5%*	*6.0%*	*6.0%*	Return on Total Cap'l	*7.0%*
9.1%	6.2%	6.2%	8.5%	7.7%	9.5%	9.6%	9.5%	8.0%	9.0%	*9.5%*	*9.5%*	Return on Shr. Equity	*11.0%*
9.2%	6.2%	6.3%	8.5%	7.7%	9.4%	9.6%	9.5%	8.0%	9.0%	*9.5%*	*9.5%*	Return on Com Equity D	*11.0%*
4.3%	1.2%	.8%	3.1%	2.7%	4.0%	4.2%	4.3%	2.9%	3.4%	*3.5%*	*3.5%*	Retained to Com Eq	*4.5%*
53%	80%	87%	63%	65%	57%	56%	55%	69%	63%	*63%*	*65%*	All Div'ds to Net Prof	*61%*

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+1.5	-2.5	+3.5
Avg. Indust. Use (MWH)	5747	5654	5781
Avg. Indust. Revs. per KWH (¢)	6.72	6.68	6.77
Capacity at Peak (Mw)	6698	7187	7523
Peak Load, Summer (Mw)	5226	5167	5184
Annual Load Factor (%)	56.2	56.1	56.4
% Change Customers (yr-end)	+.2	+.2	+.3
Fixed Charge Cov. (%)	332	330	335

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '20-'22
Revenues	--	1.0%	2.5%
"Cash Flow"	2.5%	4.0%	4.5%
Earnings	5.0%	7.0%	6.0%
Dividends	5.0%	3.0%	5.0%
Book Value	5.0%	4.0%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	628.6	612.7	764.0	596.4	2601.7
2015	590.8	589.6	732.8	546.0	2459.2
2016	569.5	621.4	764.7	606.5	2562.1
2017	*590*	*640*	*785*	*665*	*2680*
2018	*600*	*650*	*800*	*680*	*2730*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.52	.40	1.10	.33	2.35
2015	.38	.46	.97	.28	2.09
2016	.46	.51	1.08	.38	2.43
2017	*.53*	*.48*	*1.10*	*.44*	*2.55*
2018	*.54*	*.49*	*1.12*	*.45*	*2.60*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.33	.34	.34	.34	1.35
2014	.34	.35	.35	.35	1.39
2015	.35	.36	.36	.36	1.43
2016	.38	.38	.38	.38	1.52
2017	.40				

BUSINESS: Westar Energy, Inc., formerly Western Resources, is the parent of Kansas Gas & Electric Company. Westar supplies electricity to 700,000 customers mostly in Kansas. Electric revenue sources: residential end rural, 33%; commercial and business, 29%; industrial, 16%; other, 22%. The company sold its investment in ONEOK in 2003 and 85% ownership in Protection One in 2004. 2016 depreciation rate: 4.2%. Estimated plant age: 17 years. Fuels: coal, 43%; nuclear, 7%; gas, 32%; renewable, 18%. Has 2,330 employees. CEO and President: Merk A. Ruelle. Chairman: Charles Q. Chandler. Incorporated: Kansas. Address: 818 South Kansas Avenue, Topeka, Kansas 66612. Telephone: 785-575-6300. Internet: www.westarenergy.com.

Great Plains' acquisition of Westar Energy is creeping along slowly. The agreement, which calls for WR investors to receive $60 (85% in cash, 15% in stock) for each of their shares, continues to face resistance from the Kansas Corporation Commission (KCC) and the Missouri Public Service Commission (MPSC). The staff of the KCC has already said it would not recommend approval of the merger because it creates unacceptably high financial risk for both current and future customers. The agency claims that paying the agreed-upon price ($8.6 billion, or $12.2 billion when debt is included) would create a larger but financially weakened company with consumers on the hook for its problems. The case will now head to a three-member panel in Kansas where a final decision has been scheduled for April 24th. Elsewhere, Great Plains has filed for formal merger approval in Missouri. The company thinks the settlement it made with the MPSC staff will help. FERC approval is also needed, but FERC can't vote on anything because it doesn't have a quorum, with only two commissioners serving now out of a normal total of five.

The company has a rate case pending. Westar has asked the KCC to adjust its prices by 1%, or $17.4 million, for the period beginning in June, 2017. The request reflects the remaining costs of mandated environmental upgrades to comply with clean air regulators, life-extension improvements to the Wolf Creek Nuclear Generating Station, and investments to protect the grid against power outages.

The board of directors raised the dividend in early 2017. The increase was $0.02 a share (5.3%) quarterly, as we had expected. The annualized distribution is now $1.60 a share. The dividend yield is well below the average for the utility industry, however. Westar is targeting a payout ratio in the range of 60%-75%.

This issue's Timeliness rank remains suspended due to the pending takeover agreement. With the price of WR stock 9% below the value of Great Plains' offer, there is decent upside potential should the deal go through. On the other hand, if the transaction were to falter, investors run the risk of a significant decline in price.

Daniel Henigson *March 17, 2017*

(A) EPS diluted from 2010 onward. Excl. nonrecur. gains (losses): '01, 27¢; '02, ($12.06); '03, 77¢; '08, 39¢; '11, 14¢. Earnings may not sum due to rounding. Next earnings report due late May.
(B) Div'ds paid in early Jan., April, July, and Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. reg. assets. In 2016: $5.38/sh. (D) Rate base determined: fair value; Rate allowed on common equity in '16: 10.0%; earned on avg. com. eq., '16: 9.0%. Regul. Clim.: Avg. (E) In mill.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	75
Earnings Predictability	85

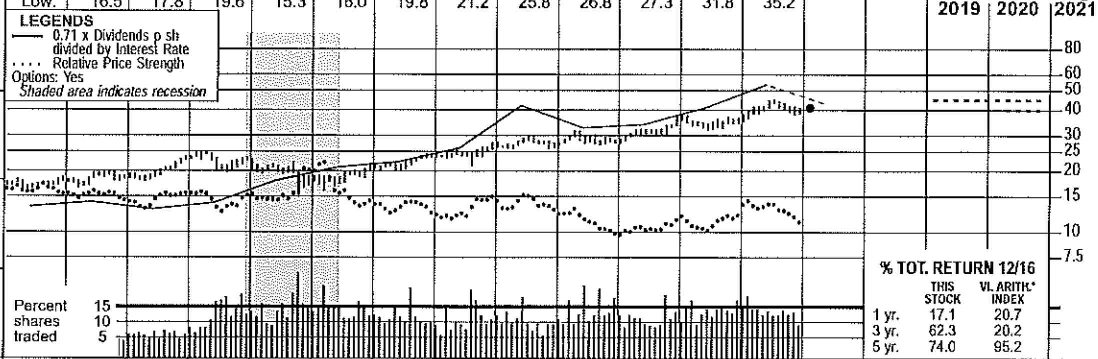
XCEL ENERGY NYSE-XEL

RECENT PRICE 41.20 | P/E RATIO 18.1 (Trailing: 19.0 Median: 15.0) | RELATIVE P/E RATIO 0.91 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 3 Lowered 11/11/16
SAFETY 1 Raised 5/1/15
TECHNICAL 3 Raised 1/13/17
BETA .60 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	20.2	23.6	25.0	22.9	21.9	24.4	27.8	29.9	31.8	37.6	38.3	45.4
Low:	16.5	17.8	19.6	15.3	16.0	19.8	21.2	25.8	26.8	27.3	31.8	35.2

Target Price Range 2019 | 2020 | 2021



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+10%)	6%
Low	40	(-5%)	3%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	1	0	0	1

Institutional Decisions

	1Q2016	2Q2016	3Q2016
to Buy	292	306	257
to Sell	231	218	254
Hld's(000)	370041	364911	355920

% TOT. RETURN 12/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	17.1	20.7
3 yr.	62.3	20.2
5 yr.	74.0	95.2

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
34.11	43.56	23.89	19.90	20.84	23.86	24.16	23.40	24.69	21.08	21.38	21.90	20.76	21.92	23.11	21.72	*21.45*	*21.65*	Revenues per sh	*23.25*
4.12	5.09	3.14	3.35	3.27	3.28	3.61	3.45	3.50	3.48	3.51	3.79	4.00	4.10	4.28	4.56	*5.05*	*5.50*	"Cash Flow" per sh	*6.25*
1.60	2.27	.42	1.23	1.27	1.20	1.35	1.35	1.46	1.49	1.56	1.72	1.85	1.91	2.03	2.10	*2.20*	*2.30*	Earnings per sh A	*2.75*
1.48	1.50	1.13	.75	.81	.85	.88	.91	.94	.97	1.00	1.03	1.07	1.11	1.20	1.28	1.36	*1.44*	Div'd Decl'd per sh B ■ †	*1.70*
3.63	7.40	6.04	2.49	3.19	3.25	4.00	4.89	4.66	3.91	4.60	4.53	5.27	6.82	6.33	7.26	*6.00*	*7.20*	Cap'l Spending per sh	*6.75*
16.37	17.95	11.70	12.95	12.99	13.37	14.28	14.70	15.35	15.92	16.76	17.44	18.19	19.21	20.20	20.89	*21.70*	*22.55*	Book Value per sh C	*25.25*
339.79	345.02	398.71	398.96	400.46	403.39	407.30	428.78	453.79	457.51	482.33	486.49	487.96	497.97	505.73	507.54	*507.95*	*507.95*	Common Shs Outst'g D	*507.95*
14.3	12.4	NMF	11.6	13.6	15.4	14.8	16.7	13.7	12.7	14.1	14.2	14.8	15.0	15.4	16.5	*18.6*		Avg Ann'l P/E Ratio	*15.5*
.93	.64	NMF	.66	.72	.82	.80	.89	.82	.85	.90	.89	.94	.84	.81	.84	*1.00*		Relative P/E Ratio	*.95*
6.4%	5.3%	6.6%	5.2%	4.7%	4.6%	4.4%	4.0%	4.7%	5.1%	4.5%	4.2%	3.9%	3.9%	3.8%	3.7%	3.3%		Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 9/30/16
Total Debt $14478 mill. Due in 5 Yrs $4930.0 mill.
LT Debt $13403 mill. LT Interest $612.9 mill.
Incl. $164.0 mill. capitalized leases.
(LT interest earned: 3.8x)

Leases, Uncapitalized Annual rentals $241.6 mill.
Pension Assets-12/15 $2883.8 mill.
Oblig. $3587.9 mill.

Pfd Stock None

Common Stock 507,952,795 shs.
as of 10/24/16
MARKET CAP: $21 billion (Large Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
9840.3	10034	11203	9644.3	10311	10655	10128	10915	11686	11024	*10900*	*11000*	Revenues ($mill)	*11750*
568.7	575.9	645.7	685.5	727.0	841.4	905.2	948.2	1021.3	1063.6	*1120*	*1170*	Net Profit ($mill)	*1350*
24.2%	33.8%	34.4%	35.1%	37.5%	35.8%	33.2%	33.8%	33.9%	35.8%	*35.0%*	*33.0%*	Income Tax Rate	*33.0%*
9.8%	12.5%	15.9%	16.8%	11.7%	9.4%	10.8%	13.4%	12.5%	7.7%	*6.0%*	*7.0%*	AFUDC % to Net Profit	*6.0%*
52.1%	49.7%	52.2%	51.6%	53.1%	51.1%	53.3%	53.3%	53.0%	54.1%	*57.0%*	*57.0%*	Long-Term Debt Ratio	*52.5%*
47.0%	49.4%	47.1%	47.7%	46.3%	48.9%	46.7%	46.7%	47.0%	45.9%	*43.0%*	*43.0%*	Common Equity Ratio	*47.5%*
12371	12748	14800	15277	17452	17331	19018	20477	21714	23092	*25575*	*26550*	Total Capital ($mill)	*30400*
15549	16676	17689	18508	20663	22353	23809	26122	28757	31206	*32825*	*34850*	Net Plant ($mill)	*40300*
6.2%	6.3%	6.0%	6.2%	5.7%	6.5%	6.1%	6.0%	6.0%	5.8%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
9.6%	9.0%	9.1%	9.3%	8.9%	9.9%	10.2%	9.9%	10.0%	10.0%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.5%*
9.7%	9.1%	9.2%	9.4%	8.9%	9.9%	10.2%	9.9%	10.0%	10.0%	*10.0%*	*10.0%*	Return on Com Equity E	*10.5%*
3.6%	3.1%	3.8%	3.7%	3.6%	4.3%	4.7%	4.5%	4.5%	4.3%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
63%	66%	59%	61%	59%	56%	54%	54%	55%	57%	*62%*	*62%*	All Div'ds to Net Prof	*64%*

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	+.3	+.2	-.6
Large C & I Use (MWH)	23875	24475	23521
Large C & I Revs. per KWH (¢)	6.23	6.47	6.10
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	21258	21429	19583
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.8	+.9	+.9
Fixed Charge Cov. (%)	321	344	358

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	.5%	--	.5%
"Cash Flow"	2.5%	4.5%	6.5%
Earnings	5.0%	6.0%	5.5%
Dividends	4.0%	4.5%	6.0%
Book Value	4.5%	4.5%	4.0%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	2783	2579	2822	2731	10915
2014	3203	2685	2870	2928	11686
2015	2962	2515	2902	2645	11024
2016	2772	2500	3040	*2588*	*10900*
2017	*2800*	*2550*	*3000*	*2650*	*11000*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.48	.40	.73	.30	1.91
2014	.52	.39	.73	.39	2.03
2015	.46	.39	.84	.41	2.10
2016	.47	.39	.90	*.44*	*2.20*
2017	*.54*	*.40*	*.90*	*.46*	*2.30*

Calendar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.27	.27	.28	.28	1.10
2014	.28	.30	.30	.30	1.18
2015	.30	.32	.32	.32	1.26
2016	.32	.34	.34	.34	1.34
2017	.34				

BUSINESS: Xcel Energy Inc. is the parent of Northern States Power, which supplies electricity to Minnesota, Wisconsin, North Dakota, South Dakota & Michigan & gas to Minnesota, Wisconsin, North Dakota & Michigan; Public Service of Colorado, which supplies electricity & gas to Colorado; & Southwestern Public Service, which supplies electricity to Texas & New Mexico. Customers: 3.5 mill. electric, 1.9 mill. gas. Elec. rev. breakdown: residential, 31%; sm. comm'l & ind'l, 36%; lg. comm'l & ind'l, 18%; other, 15%. Generating sources not available. Fuel costs: 43% of revs. '15 reported depr. rate: 2.8%. Has 11,700 employees. Chairman, Pres. & CEO: Ben Fowke. Inc.: MN. Address: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Internet: www.xcelenergy.com.

Xcel Energy's utility in Minnesota is awaiting a ruling from the state commission on its multiyear regulatory settlement. The settlement between Northern States Power, the commission's staff, and some (but not all) intervenors calls for electric rate increases of $75.0 million in 2016 (plus $37.4 million to compensate the utility because kilowatt-hour sales fell short of expectations), $59.9 million in 2017, no change in 2018, and $50.1 million in 2019. The allowed return on equity would be 9.2%, and the common-equity ratio would be 52.5%. The commission's decision is expected in June, and would be retroactive to 2016. NSP is now collecting an interim tariff hike of $163.7 million.

NSP received a rate order in Wisconsin, Southwestern Public Service got one in Texas, and SPS has a case pending in New Mexico. In Wisconsin, NSP's tariffs were raised by $22.5 million (electric) and $4.8 million (gas) at the start of 2017, based on a return of 10% on a common-equity ratio of 52.5%. In Texas, the regulators approved a settlement calling for an electric increase of $35.2 million, retroactive to July 20, 2016. In New Mexico, SPS filed for an electric hike of $41.4 million, based on a return of 10.1% on a common-equity ratio of 54%. New rates are expected to take effect in the second half of 2017.

Frequent regulatory activity is necessary to reduce the effects of regulatory lag. As a group, Xcel's utilities are underearning their allowed ROE by about eight-tenths of a percentage point. Rate relief is the key factor in the company's earnings growth. Our share-net estimates are within the company's targeted ranges of $2.17-$2.22 and $2.25-$2.35 for 2016 and 2017, respectively.

We expect a dividend increase at the board meeting in February. We think the directors will raise the quarterly disbursement by two cents a share (5.9%). Xcel's goals are annual dividend growth of 5%-7% and a payout ratio of 60%-70%.

This high-quality stock has a valuation that is close to the utility norms. The dividend yield and 3- to 5-year total return potential are about equal to the industry averages.

Paul E. Debbas, CFA *January 27, 2017*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '02, ($6.27); '10, 5¢; '15, (16¢); gains (losses) on discontinued ops.: '03, 27¢; '04, (30¢); '05, 3¢; '06, 1¢; '09, (1¢); '10, 1¢. Next earnings report due early Feb. (B) Div'ds historically paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '15: $5.63/sh. (D) In mill. (E) Rate base: Varies. Rate allowed on com. eq. (blended): 9.8%; earned on avg. com. eq., '15: 9.5%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	100

CASE: UE 319
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 510

Security Markets News that Investors and Money Managers are Experiencing

Exhibits in Support of Opening Testimony

June 16, 2017

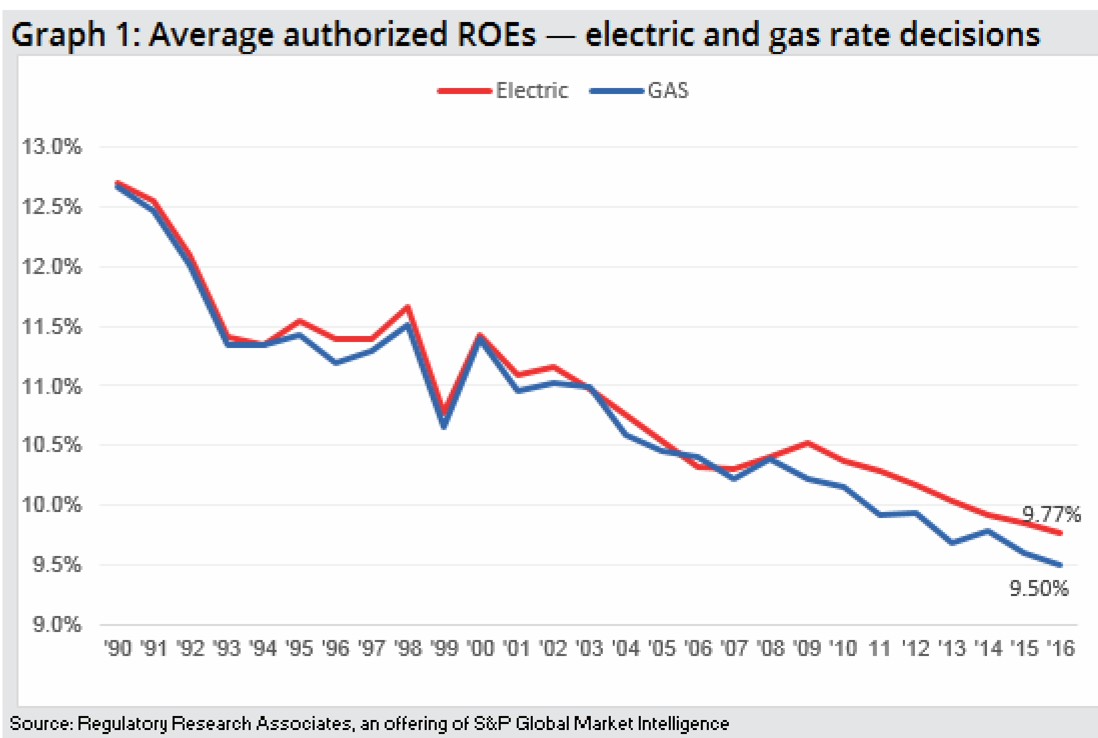
Security Market News

ROE Authorizations in 2016
Slightly Below Those in 2015

by Dennis Sperduto — Regulatory Research Associates (RRA)
An Affiliate of SNL Financial LC and S&P Global Market Intelligence, Jan. 19, 2017
https://www.snl.com/web/client?auth=inherit#news/article?id=39089209&KeyProductLinkType=4

The **average ROE authorized for electric utilities** was 9.77% in rate cases decided in 2016, compared to 9.85% in 2015. There were 42 electric ROE determinations in 2016, versus 30 in 2015. This data includes several **limited issue rider** cases; **excluding** these cases from the data, the average authorized ROE was **9.6% in rate cases decided in 2016, the same as in 2015**. RRA notes that this differential in electric authorized ROEs is largely driven by **Virginia** statutes that authorize the Virginia State Corporation Commission to approve **ROE premiums** of **up to 200 basis points for certain generation projects** (see the Virginia Commission Profile). The **average ROE authorized gas utilities was 9.5% in 2016 versus 9.6% in 2015**. There were 24 gas cases that included an ROE determination in 2016, versus 16 in 2015.

This data is included in a study titled "Major Rate Case Decisions — January-December 2016" issued Jan. 18 by Regulatory Research Associates, an offering of S&P Global Market Intelligence.



In the report, RRA notes that since 2010, the number of rate cases has moderated somewhat but has been 90 or more in the last five calendar years. There were 111 electric and gas rate cases resolved in 2016, 92 in 2015, 99 in both 2014 and 2013, and 110 in 2012, and this level of rate case activity remains robust compared to the late 1990s/early 2000s. Increased costs associated with environmental compliance, including possible CO2 reduction mandates, generation and delivery infrastructure upgrades and expansion, renewable generation mandates and employee benefits argue for the continuation of an active rate case agenda over the next few years.

RRA also notes that **interest rates have declined significantly since 2008** and **average authorized ROEs have declined modestly**. In addition, the report notes the increased utilization of limited issue rider proceedings that allow utilities to recover certain costs outside of a general rate case and typically incorporate previously determined return parameters.

If the Federal Reserve continues its policy initiated in December 2015 to gradually raise the federal funds rate, utilities eventually would face higher capital costs and would need to initiate rate cases to reflect the higher capital costs in rates. However, the magnitude and pace of any additional Federal Reserve action to raise the federal funds rate is quite uncertain.

The report compares, since 2006, average authorized ROEs by settled versus fully litigated cases, general rate cases versus limited issues rider proceedings, and vertically integrated cases versus delivery only cases. For both electric and gas cases, no pattern exists in average annual authorized ROEs in cases that were settled versus those that were fully litigated. In some years, the average authorized ROE was higher for fully litigated cases, in others it was higher for settled cases, and in a few years the authorized ROE was similar for fully litigated versus settled cases.

Regarding electric cases that involve limited issue riders, over the last several years the annual average authorized ROEs in these cases was typically at least 100 basis points higher than in general rate cases, driven by the ROE premiums authorized in Virginia. Limited issue rider cases in which an ROE is determined have had extremely limited use in the gas industry.

Comparing electric vertically integrated cases versus delivery only proceedings, RRA finds that the annual average authorized ROEs in vertically integrated cases are from roughly 40 to 70 basis points higher than in delivery only cases, arguably reflecting the increased risk associated with generation assets.

A chronological listing of the major rate case decisions during 2016 is provided in the report, as well as historical summary data going back to 1990.

For a complete, searchable listing of RRA's in-depth research and analysis, please go to the SNL Research Library.

For a full listing of Past and Pending Rate Cases, rate case statistics, and upcoming events, visit RRA's Home Page.

Census Says U.S. Population Grew at Lowest Rate Since Great Depression This Year

by Janet Adamy and Paul Overberg — WSJ — Dec. 20, 2016

New York State shrunk for first time in decade, while Utah and other western states grew.

The U.S. population this year grew at its lowest rate since the Great Depression, and the state of New York shrunk for the first time in a decade, according to Census Bureau figures released Tuesday.

An uptick in deaths, a **slowdown in births** and a slight drop in immigration all damped American population growth for the year ended July 1. The **0.7% increase in the U.S. population, to 323.1 million people, was the smallest rise on record since 1936-37**, according to William Frey, a demographer at the Brookings Institution.

The new figures show Americans continue to leave the north for western states, with Utah, Nevada, Idaho, and several others in that region topping the country in percentage growth of their populations. Besides New York, Pennsylvania and Illinois also shrunk in notable ways, with the land of Lincoln losing more people than any other state.

New York, whose loss of 1,900 people put its population at 19.7 million, is suffering from an outflow of residents to other states. It has an aging population that is leaving to retire in warmer places such as Florida, or staying put and dying.

“As a state that has more people leaving than going [in], that is not a good thing,” said Jan Vink, a researcher at Cornell University’s program on applied demographics. “People claim it’s about the taxes, it’s about the weather. There are many reasons.”

Utah, the fastest-growing state this year, with a **2% gain**, added almost 61,000 people to bump its population to 3.1 million people. Gains in technology and other jobs have led to tighter labor markets, housing shortages, and rising school enrollments, said Pamela Perlich, director of demographic research at the University of Utah’s Kem C. Gardner Policy Institute.

“There is a new economy being created out of the carnage of the Great Recession, and in a lot of those new growth areas, Utah seems to be at the forefront,” Ms. Perlich said. “You roll back 40 years ago, and we were really pretty isolated and much more parochial here.”

Central Bank Nudges Up Benchmark Federal-Funds Rate by a Quarter Percentage Point to between 0.50% and 0.75%

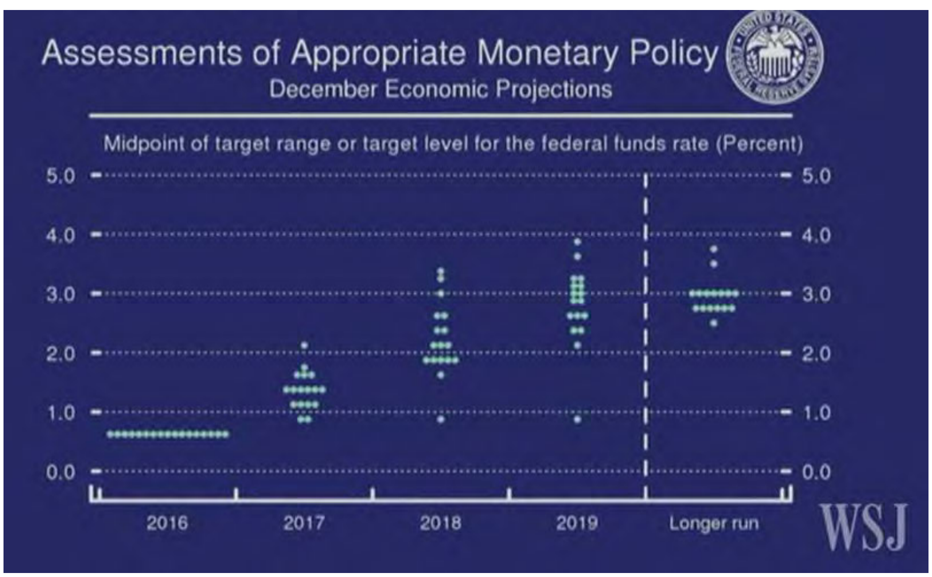
by Harriet Torry — WSJ — Dec 14, 2016

Here are a few takeaways from today's meeting.

The Federal Reserve is in wait-and-see mode on the Trump economy. They're clearly paying attention to the debate over fiscal policy but aren't ready to move forecasts yet until they have a clearer idea what the president will do.

Janet Yellen isn't picking any fights with President-elect Trump. She had several opportunities to offer critiques of some of the ideas that have been floated for economic policy but refrained from taking the bait. She emphasized the importance of the Federal Reserve's independence several times, a possible signal that she would be happy to leave President Trump alone so long as he returns the favor.

Don't read too much into the Fed's plan to raise rates three times, instead of two times, next year. She emphasized that she considers it a "very modest adjustment" with only some people on the Federal Open Market Committee moving their projections. That will put even more emphasis on the economic projections the Fed will release **in March**. By then, they'll have a much **better idea** how changes in the economy are shaping up.



It may have been an omission because so many questions were focused on the election, but Ms. Yellen didn't mention any particular downside risks to the economy right now. (Typically something about China's slowdown or Europe's debt crisis creeps into her remarks.) That just goes to show how much the emphasis has shifted.

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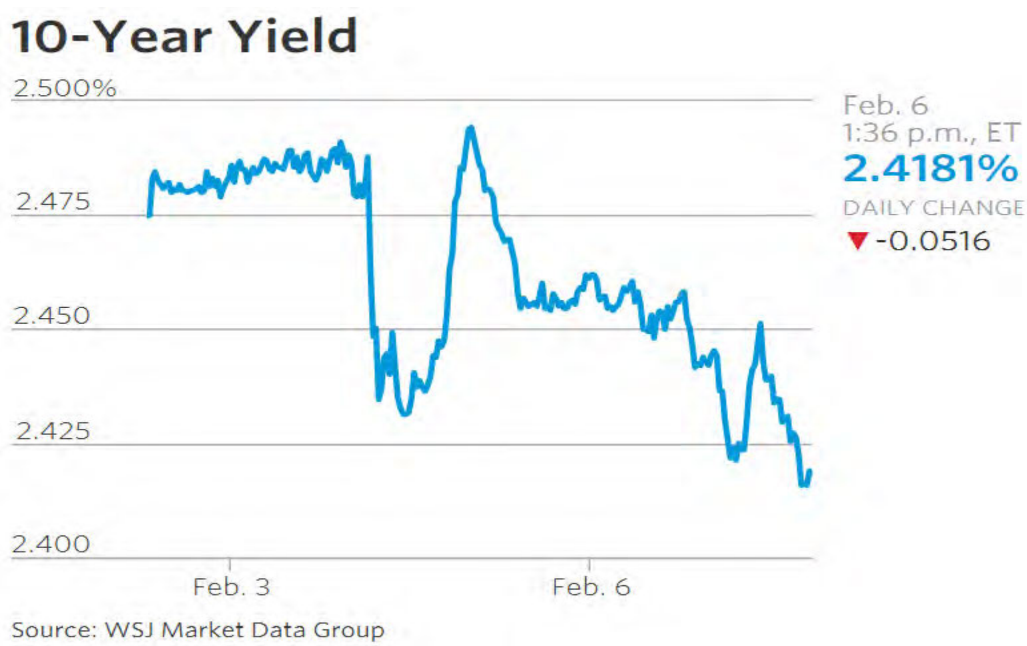
Investors Embrace U.S. Government Bonds, Bunds as French Bonds Slump

by Min Zeng — WSJ — Feb. 6, 2017

Political uncertainty in Europe stokes demand for haven assets.



Prices of U.S. government bonds and German bunds rallied Monday, as political **uncertainty in Europe sent investors piling into assets considered as harbors** to protect capital.

Reflecting the angst, investors sold government bonds in France, Italy, Spain, and Greece, sending the yield on the 10-year French bond to the highest since September 2015. The yield premium investors demanded to hold the 10-year French bond relative to the 10-year German bund, the benchmark for debt markets in the euro-zone, widened to the highest level since November 2012.

The main boost for haven flows is the **muddy presidential election outlook in France** amid a rise in populist politics that resulted in the U.K.'s referendum to exit from the European Union and a victory by Donald Trump in the U.S. Election.

French presidential candidate François Fillon faced mounting calls to resign the center-right Republican nomination under allegations of improper use of taxpayer funds. Marine Le Pen, a far right leader, has threatened to pull France out of the euro-zone.

Investors are **concerned** that if **populism** prevailed in France, it would **threaten** the **stability of the countries that share euro as the common currency**.

“If France leaves the euro, it likely will be the beginning of the end for the euro as we know it,” said Larry Milstein, head of government and agency trading at R.W. Pressprich & Co. “The polls currently show that in a runoff election Le Pen will not win, but we have seen these polls be wrong in the past and that concerns investors in this case.”

In recent trading, the **yield** on the benchmark **10-year Treasury note** was 2.426%, according to Tradeweb, compared with 2.496% Friday. Yields fall as bond prices rise.

The **10-year German bund** yield recently **fell** to 0.371%, according to Tradeweb.

”We have rising political jitters, which is favorable” for asset allocation into Treasurys and bunds, **said Boris Rjavinski, interest-rate strategist at Wells Fargo** Securities LLC.

The yield on the 10-year French government bond Monday touched 1.156%, the highest since September 2015, according to Tradeweb. It was recently at 1.140%, up from 0.685% at the end of 2016.

The yield premium investors demanded to hold the 10-year French bond relative to the 10-year German bund was 0.77 percentage point recently, up from 0.47 percentage point at the end of December, according to Tradeweb.

The selling in French bonds rippled into government bond markets in Spain, Italy, Portugal, and Greece, sending yields higher.

Bond yields in the euro-zone remain at low levels from a historical standpoint thanks to large bond buying from the European Central Bank and the broader picture of low yields globally.

Concerns over Greece’s debt payments added to investors’ migration into Treasurys and bunds, said traders. Greece is struggling under its austerity regime, and new questions are mounting as to whether it can satisfy its bailout terms.

“What makes it contain potential seeds of instability for financial markets is that the Greek story will be playing out in the midst of some broader uneasiness in the euro-zone,” said Anthony Karydakis, chief economic strategist at Miller Tabak & Co.

Policy uncertainty in the U.S. has been whipsawing the U.S. bond market. The 10-year Treasury yield reached a two-year high of 2.6% in mid-December from 1.867% on the U.S. Election Day. The yield has been gyrating largely between 2.3% and 2.6% over the past weeks.

Selling Treasury bonds had been the popular trade for investors to bet that the prospect of large fiscal spending, lower taxes and lighter regulation would lead to stronger economic growth. But the reflation trade has been tempered by concerns over Mr. Trump’s protectionism on trade and his action to curb immigration and tighten border control.

"The more time Trump devotes to the issues of immigration, health care and other 'non-pro-business' initiatives, the less likely those economy-friendly changes become," said Ian Lyngen, head of U.S. rates strategy at BMO Capital Markets. "Markets have nonetheless been dutifully awaiting more evidence that a round of economic stimulus is forthcoming."

The Federal Reserve's gradual approach in raising short-term interest rates also reduces the risk of a swift rise in bond yields, say analysts.

Friday's employment report showed solid jobs growth, yet wage inflation pressure remained relatively contained, bolstering **market expectation that the Fed is likely to wait until this summer to raise interest rates**. The fiscal policy **uncertainty added to the Fed's case to wait** for a few more months **before tightening monetary policy**, say analysts.

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Fed Leaves Policy Rate Unchanged, Offers No Hint on When It Might Next Move

by David Harrison — WSJ — Feb. 1, 2017

The central bank says it expects inflation to rise to 2% 'over the medium term'

Left: Federal Reserve Chair Janet Yellen discussed monetary policy and economic outlook Jan. 19 at Stanford University.

The Federal Reserve said Wednesday it remains on track to **gradually raise short-term interest rates this year** and gave no hint about when the next increase might come.

Following a two-day policy meeting, officials unanimously held their benchmark rate steady in a range between 0.50% and 0.75%, while noting in a statement some recent improvements in the economy. They lifted rates by a quarter percentage point in December and penciled in three quarter-point moves in 2017.

Investors hadn't expected the Fed to move Wednesday and were looking for a signal about their next meeting on March 14-15. As of Wednesday morning, investors placed a roughly 25% probability of a rate increase then.

The central bank's meeting this week came as the U.S. economy shows signs of strengthening. Several officials have said the labor market is now operating at close to full strength with strong job growth keeping the unemployment rate at 4.7%. Inflation has also moved closer to the Fed's 2% target, coming in at 1.6% in December over the previous year. Some of the rise can be attributed to stabilizing oil prices. The Fed said it expects "inflation will rise to 2% over the medium term."

Economic growth, which slumped in the first part of 2016, appears to have found a firmer footing, with the economy growing at 1.9% in the fourth quarter from the fourth quarter of 2015.

The statement also noted that "measures of consumer and business sentiment have improved of late."

A gauge of consumer confidence hit a 15-year-high in December. Recent data also suggest that investors and consumers see stronger growth ahead. Market-based measures of inflation expectations have been rising in recent months.

The Fed didn't mention any new developments that would knock it off its anticipated path of rate increases. The central bank statement described the risks to its outlook as "roughly balanced," meaning officials consider it equally likely that the economy will perform better or worse than projected. Officials said they would continue to "closely monitor inflation indicators and global economic and financial developments."

But economic volatility can emerge unpredictably.

In December **2015**, for instance, **Fed** officials saw enough reason for **optimism** that they raised interest rates for the first time in nearly a decade and **anticipated four quarter-point rate increases in 2016**. That **optimism faded** in the first few months of 2016, when **economic turmoil in China** sent shivers through global markets. That was **followed by a U.S. hiring slump** in the spring, **market turbulence following the U.K.'s Brexit vote in June** and uncertainty about the possible effects of the **U.S. presidential election in November**—all of which led the Fed to hold off on raising rates through most of the year. **In the end**, it **lifted borrowing costs just once in 2016**.

Some officials have said President Donald Trump's proposed tax cuts and spending increases could cause the economy to grow faster than projected, which could cause too much inflation and lead the Fed to raise rates more than anticipated. Mr. Trump has also vowed to rewrite trade agreements, which could lead to more economic and financial uncertainty.

In a recent speech in San Francisco, Federal Reserve Chairwoman Janet Yellen mentioned "the **potential for changes in fiscal policy to affect the economic outlook** and the appropriate policy path."

The Fed's statement Wednesday made no mention of fiscal policy or of Mr. Trump's proposals.

Officials are set to release updated economic projections following their March meeting and Ms. Yellen is expected to hold her quarterly press conference. By then, officials will have inflation data for January as well as two more employment reports, for January and February.

Ms. Yellen is also scheduled to speak before Congress on Feb. 14 and 15, where she could offer an update on the economy's progress and the Fed's plans for interest rates.

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The Economy's People Problem

by Justin Lahart — WSJ — Feb 3, 2017

Productivity data are weak again, showing the challenges faced by President Trump to boost growth, especially if he cuts immigration.

Work at a Boeing Co. aircraft-interior facility in South Carolina.
The U.S. has been struggling to raise the size and productivity of its workforce

The U.S. economy has a people problem. There may not be much that President Donald Trump can do to improve the situation, and there is a danger he could make it even worse.

People drive the pace of economic growth, and they do it in three main ways: First, they can add to their numbers — **more workers produce more goods**. Second, a **greater share the population can hold jobs**. And third, the people working can **do** their **jobs more efficiently, boosting productivity**.

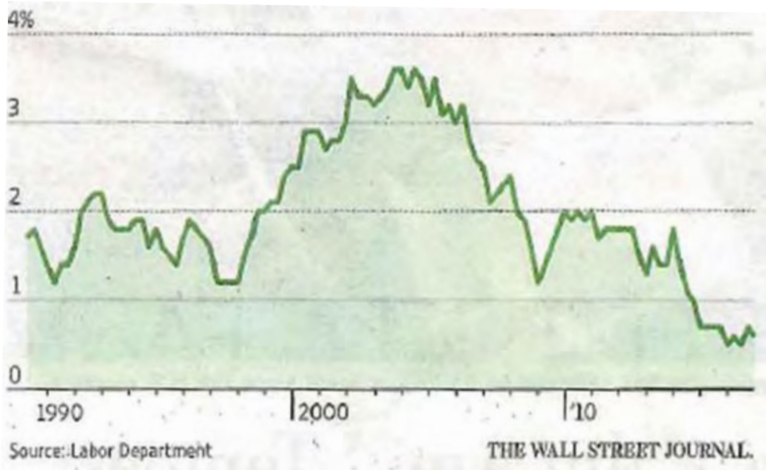
On all those fronts, the U.S. has been struggling.

Population growth has slowed, and is forecast to slow further in the decades ahead. By 2026 the population will be growing about 0.2% a year, according to Census projections, versus 0.7% last year. Those projections are based in part on expectations that the U.S. will have net immigration of about 1.3 million people a year over the next decade. If Mr. Trump follows through with his hard line on immigration, those projections may be too high.

The share of the population in the labor force has fallen over the past decade, partly because of the damage exacted by the financial crisis, but also because the population is aging. So while it is possible that, if the job market keeps improving more people could be drawn into the workforce, there is a limit on any gains. Many of the people on the sidelines may at least initially lack the skills to do available jobs well.

Efficient Frontier

Five-year rolling average of annual productivity growth



Finally, **efficiency gains have weakened**. The Labor Department on Wednesday reported that productivity, as measured by what the average worker produces in an hour, was up just 1% in the fourth quarter from a year earlier. That is about the pace of the past few years, and compares with average annual productivity gains of 2.1% during the 1990s.

Getting productivity going again won't be easy. Companies' capital spending has been weak for over a decade, meaning **workers aren't getting cutting-edge technology that could boost their productivity**. Mr. Trump's promised tax cuts and regulation rollbacks could at least temporarily lift capital spending, which could boost productivity and growth.

But productivity gains could be offset by more restrictive trade policies. That is because the big benefit of trade is that it allows countries to focus on what they do best — that is, allocate their workers to the areas where they can be most productive.

Investors are focused on how Mr. Trump's tax and fiscal policies might boost the economy. But ultimately, economic growth will be set by how much of a people person Mr. Trump turns out to be.

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GDP Expands Tepid 1.9% on Wider Trade Deficit

by Ben Leubsdorf — WSJ — Jan. 27, 2017

The U.S. economy decelerated in the final three months of 2016, returning to a lackluster growth rate

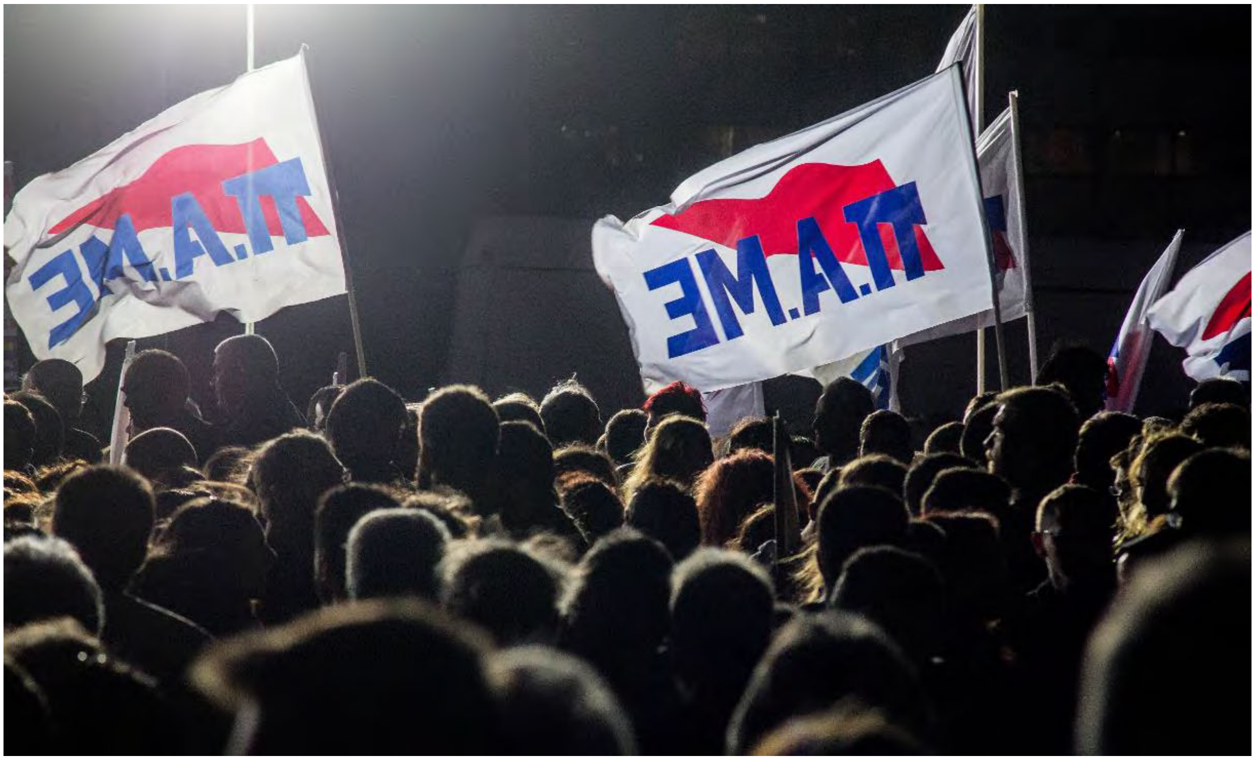
Gross domestic product, a broad measure of the goods and services produced across the economy, expanded at an inflation rate and seasonally adjusted annual rate of **1.9% in the fourth quarter**, the Commerce Department said Friday.

That was a slowdown from the third quarter's 3.5% growth rate, which had been the strongest reading in two years, and was **in line with the 2% growth rates that have prevailed through most of the expansion which began in mid-2009**. Economists surveyed by The Wall Street Journal had expected a 2.2% growth rate in the final three months of 2016.

Greek Bond Could Set Deadline on Country's Talks with Creditors

by Christopher Whittall — WSJ — Feb. 10, 2017

Trading in the €2 billion bond has been volatile



Greek unions protest against the arrival of the country's creditors' representatives in Athens during talks last October

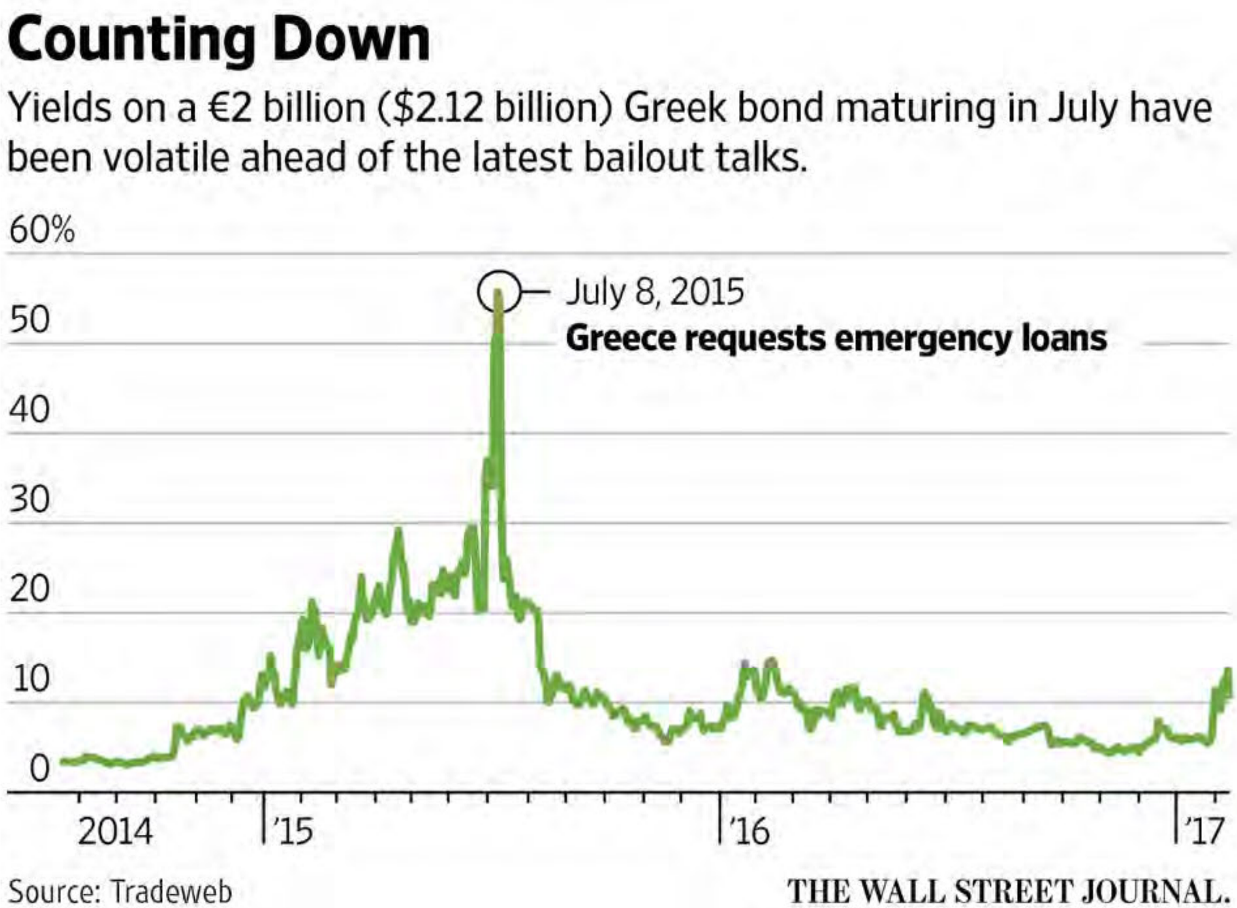
Greece made a triumphant return to bond markets in 2014, proclaiming it had turned the corner two years after its near-exit from the euro.

Fast forward to 2017 and **one of those bonds** has come back to haunt it, acting as a hard deadline for when Greece must get money from its creditors.

Trading in the €2 billion (**$2.13 billion**) bond in question — which **matures in July** — has been volatile. In recent days the **yield has shot above 15%** from as low as 5% in late January, according to Tradeweb. Rising yields mean falling prices. The yield declined to 10.4% Friday from 13.6% at the previous day's close following reports that the International Monetary Fund and Greece's European creditors had agreed on a common stance on negotiations with the country.

But as ever with **Greece, analysts predict a bumpy road ahead**.

Greece needs to secure a deal to pay private investors holding the debt coming due in July, along with a chunk of money owed to its public creditors, including the European Central Bank and the IMF.



Clouding the picture are a series of **elections** in the rest of the euro-zone, including the **Netherlands** in March, **France** in the spring and **Germany** in September. **Leaders in Germany, in particular, won't want to appear to voters to be letting Greece off the hook**.

€1.40 billion on Feb. 10, 2017
Owed to: Treasury bill holders

€1.62 billion on Feb. 27, 2017
Owed to: European Stability Mechanisr

€1.40 billion on March 3, 2017
Owed to: Treasury bill holders

Greek politicians are facing domestic political pressures as well to stand their ground. The left-wing Syriza government is behind in the polls and some analysts say the chance of early elections has increased in the coming months.

The political situation inside and outside of Greece "makes concluding the review very difficult," said Athanasios Vamvakidis, head of G-10 foreign-exchange strategy at Bank of America Merrill Lynch.

The main points of contention revolve around Greece's budgetary finances, structural reforms and the thorniest issue of all: debt relief.

Mr. Vamvakidis said pressures on the Greek government's finances will be needed for an agreement to be concluded, a familiar playbook seen during previous Greek bailout talks. That will likely begin in **May or June** as **Greece starts to run out of money**, he says.

"**July is the real deadline** because this is when, **if** you **don't repay bonds**, you're going to **have to default**," he said.

Kathrin Muehlbronner, senior vice president at Moody's Investors Service, said Thursday she expects Greece to implement measures required by its creditors such as labor-market reforms. But the risk of early elections is increasing, she said.

That could bring in a more reform-minded government. But meanwhile: "Greece's economy would be hit again by prolonged uncertainty after having just started to record positive growth," she said.

Despite the gyrations in Greece's short-term debt, many investors still think a last-ditch agreement before the 2017 bond matures is the most likely outcome.

Greek bonds also weakened ahead of a similar bailout review last year, before rallying later in the year. The 2017 bond still yields far below the roughly 56% level it spiked to during the summer of 2015. Back then, Greece flirted with an exit from the euro area amid fractious talks with its creditors that were eventually resolved.

Some investors think Greece will again muddle through.

Mark Dowding, co-head of investment-grade debt at BlueBay Asset Management, said he plans to keep the small amount of Greek long-dated government bonds he holds as part of some of the firm's hedge-fund strategies.

"I don't see Greece leaving the euro for the time being. I don't see them defaulting on their debt. Therefore it's an attractive yield," he said.

Analysts say this shouldn't be the last time Greek bailout talks dominate news headlines though, **predicting** the **contentious issue of debt relief** is **unlikely to be resolved**.

"It is **very difficult for the Europeans to agree on** this **ahead of the German elections**," said Mr. Vamvakidis.

On that issue, at least, he says the **most likely outcome** is once again "to **kick the can down the road**."

Rates Likely to be Left Alone in Uncertain Times

by Martin Crutsinger, Associated Press — Oregonian — February 1, 2017

The Federal Reserve is all but sure to leave interest rates alone when it ends a policy meeting Wednesday, at a time of steady gains for the U.S. economy, but also heightened uncertainty surrounding the new Trump administration.

The Fed will likely signal that it wants further time to monitor the progress of the economy and that it still envisions a **gradual pace of rate increases ahead**.

"I don't look for the Fed to do anything this week," said Sung Won Sohn, an economics professor at the Martin Smith School of Business at California State University. "They are starting to get their ducks in a row for further rate hikes, but it will be too soon to pull the trigger."

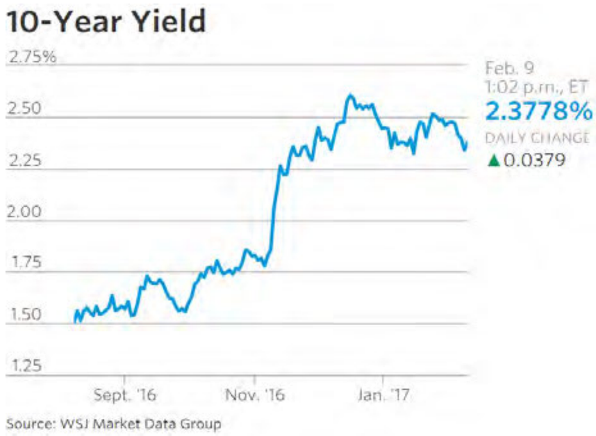
The Fed's two-day meeting will end with a policy statement that will be studied for any signals of its outlook or intentions. At the moment, **most economists foresee no rate increase even at the Fed's next meeting in March**, especially given the unknowns about how President Donald Trump's ambitious agenda will fare or whether his drive to cancel or rewrite trade deals will slow the economy or unsettle investors.

Last month, the Fed modestly raised its benchmark short-term rate for the first time since December 2015. It had kept the rate at a record low near zero for seven years, to help rescue the banking system and energize the economy after the 2008 financial crisis and ensuing recession.

When it raised rates last month, the Fed indicated that it expected to do so three more times in 2007.

Treasury Yields Fall As Inflation Signs Ease

by Sam Goldfarb — WSJ — Feb. 8, 2017



U.S. government bonds strengthened Wednesday, extending recent gains as **investors** further **dialed back expectations for higher inflation and tighter monetary policy**.

The **yield on the benchmark 10-year Treasury note settled at 2.349%,** its lowest close since Jan. 17, compared with 2.389% Tuesday. It fell as low as 2.325% earlier in the day, according to Tradeweb, but rebounded following a lackluster auction of new 10-year notes.

Yields fall when bond prices rise.

Though still within their range for this year, Treasury yields have declined in recent days due to a variety of **factors**, including **mounting political risks in Europe**, **uncertain fiscal policy in the U.S**. and signs that **wages in the U.S. aren't rising** as **fast** as many economists had expected.

The bond market's recent momentum arguably started **last Wednesday** when the **Federal Reserve kept interest rates steady and gave little indication about when it will next raise rates**. That surprised some investors who had expected a stronger signal that a March rate increase is possible.

The market got another boost Friday when the latest jobs report showed disappointing wage growth. It then began a more robust rally Monday amid concerns that the far right **French** presidential candidate Marine Le Pen could win the French **election** and make good on her promise to pull France out of the euro-zone — an outcome that could destabilize the financial markets and drive investors to the safety of haven debt.

Against this backdrop, investors have continued to be frustrated by developments in Washington, where lawmakers appear to be making slow progress on policies, such as an overhaul of the tax code, which could lead to faster economic growth, higher inflation and more bond issuance.

Higher inflation erodes the fixed returns of bonds and **can lead the Fed to tighten monetary policy**, further **diminishing the value of government debt**. **Larger budget deficits also tend to lead to higher bond yields due to the increased supply of bonds**, **while faster economic growth can enhance the appeal of riskier assets at the expense of Treasurys**.

Hopes for more expansive fiscal policies were a main reason why the **10-year yield soared to 2.6% in mid-December from 1.867% on Election Day. Yet those expectations have since been tempered** as the political debate has largely centered on President Donald Trump's protectionist stance on trade and his action to curb immigration.

"The constant to and fro in Washington on issues that aren't immediately related to fiscal stimulus, tax reform and other things that comprised the Trump trade is backing people away from some of their inflation expectations," said Jim Vogel, interest-rates strategist at FTN Financial.

Investors have pared bets on inflation by selling **Treasury inflation-protected securities** and buying Treasury bonds.

The **10-year break-even rate, the yield premium investors demand to hold the benchmark 10-year Treasury note relative to the 10-year TIPS, fell to 1.964 percentage points Wednesday** from 1.991 percentage points Tuesday and its recent high of 2.069 percentage points on Jan. 27, according to Tradeweb. **That implies investors now expect inflation to run below the Fed's 2% annual target over the next 10 years.**

Meanwhile, **Fed-fund futures**, which are used to place bets on central bank policy, **showed Wednesday that investors and traders see a 59% likelihood of a rate increase by the Fed's policy meeting in June, according to CME Group**. The odds were 65% Tuesday and **above 70% in late January**.

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Ultra-long Debt Sells Despite Politics

by Christopher Whittall and Emese Bartha — WSJ — Feb. 7, 2017

Flurry of long-bond sales underlines strong appetite for yield even amid concern of pickup in inflation:

Political risk is on the rise in Europe and bonds have been selling off. But that hasn't stopped **investors** from **snapping up ultra-long-dated debt** — a trend that emerged in 2016 when investors were more concerned with hunting for returns than shielding themselves from losses.

Belgium on Tuesday became the latest euro-zone country **to sell** long-dated bonds, including one slug of **debt that doesn't come due until 2057**. It **follows** a string of **long bonds that France issued in January**, despite the country facing presidential elections in April that this week helped push yields on the country's 10-year government bond to their largest premium over German yields since late 2012, according to Tradeweb.

Other countries have found buyers for long-dated debt despite bond yields moving higher in recent months from their record lows reached last summer. Yields rise when bond prices fall.

Some of the largest U.S. companies are also still **raising money at long maturities**. In the U.S., where the $13 trillion U.S. Treasury market led the lurch higher in global yields, January marked the busiest start to the year on record for high-grade dollar-denominated corporate debt issuance, according to Dealogic data going back to 1995.

Last week alone, Apple Inc., AT&T Inc., and Microsoft Corp. sold $37 billion of bonds between them, including tranches of debt that didn't mature for 40 years in some cases.

The flurry of long-bond deals underlines the strong appetite for yield despite widespread concern that bonds could continue to weaken over the course of the year if global inflation starts to pick up. Inflation erodes the value of the payments that fixed-rate bond investors receive over many years.

Also fueling demand for longer-dated bonds are investors such as pension funds or insurance companies that need to match lengthy liabilities.

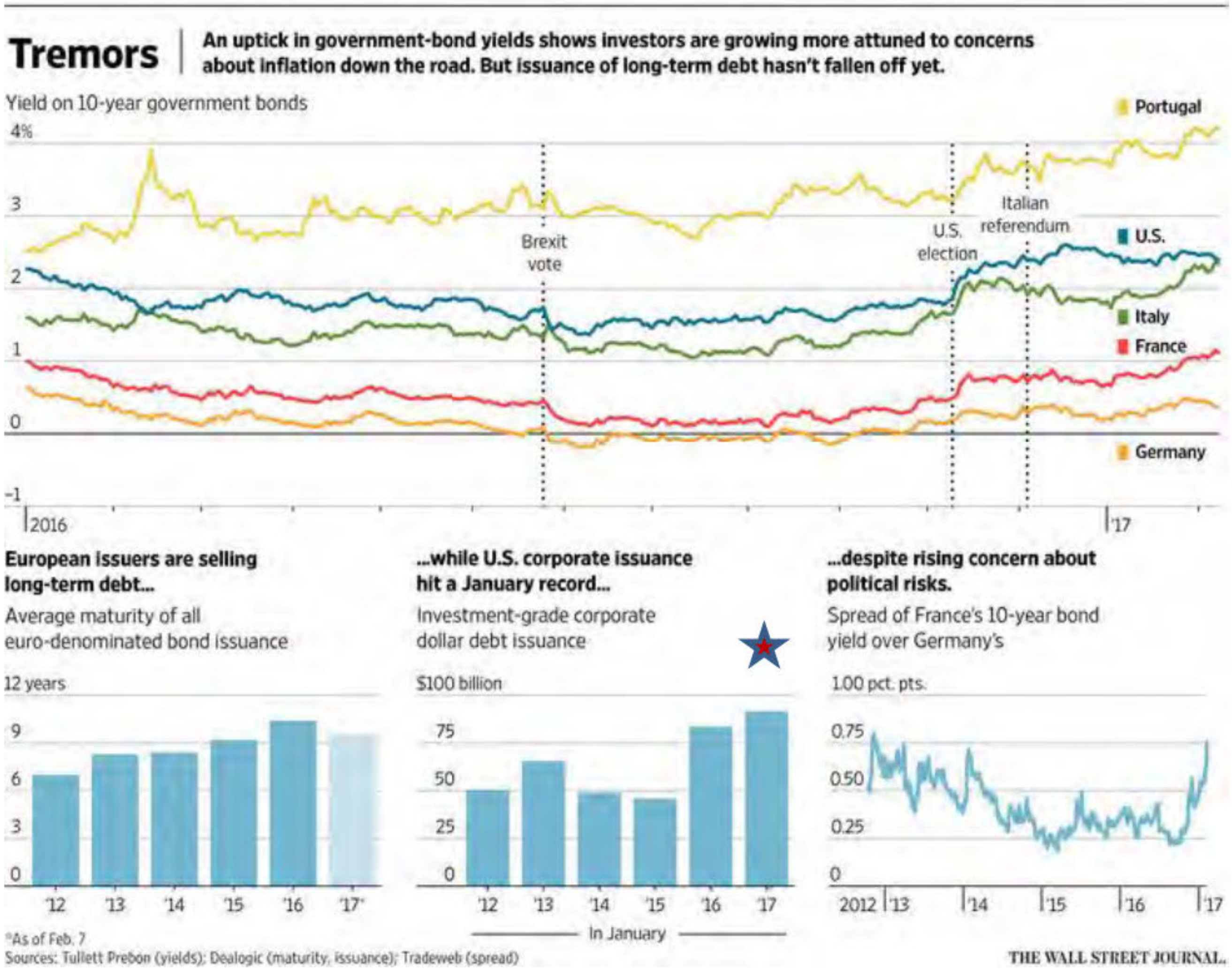
"Fixed income is still a place investors want to be," said Lee Cumbes, head of public-sector debt for Europe, Middle East and Africa at Barclays.

Meanwhile, **issuers** still **want to** take the opportunity to "**term out** [their] **debt whilst** the **demand for that yield and duration is there**," Mr. Cumbes added. **Duration is the sensitivity of a bond's price to changes in interest rates**.

That **demand** was again **evident** in Belgium's bond deal Tuesday. There were more orders for the 2057 bond than for another tranche of debt maturing in 2024, according to bankers on the deal, **allowing** Belgium to **lower** the **interest rate** it paid on the bond to around 2.3% from initial guidance that was slightly higher.

Belgium is no stranger to long-dated debt issuance. **Last y**ear, it **sold** a €100 million ($107.5 million) **century bond in** a **privately placed deal, as well as** 30-year and **50-year debt in public markets**.

That put the euro-zone's sixth-largest economy at the forefront of a trend that also saw **Italy and Spain** issue **50-year debt** for the first time and **Austria** sell a **70-year bond**. Finland has hired banks for a dual bond transaction, looking to issue new bonds that mature in 2022 and 2047, according to a deal announcement on Tuesday.



Other prominent long-dated deals in 2017 include 30-year and 26-year bonds issued by the European Stability Mechanism and European Financial Stability Facility, respectively, two of the euro area's bailout funds.

The average maturity for all euro-denominated debt sales in 2016 was 10.4 years, according to Dealogic, compared with an average of 7.9 years for the previous five years. The average maturity so far in 2017 is 9.5 years.

The continued demand for long debt comes despite heightened debate over when the **European Central Bank may scale back its stimulus**, which has supported bond markets in recent years, and growing political risk on the Continent.

For many, the **French elections** are a major source of **concern**. The leader of France's far-right National Front party, Marine Le Pen, who supports the removal of France from the euro, is riding high in the polls, though she isn't currently projected to win the country's presidency.

The gap in yield between the 10-year bonds of France and Germany has risen to more than 0.7 percentage point, compared with around 0.2 percentage point in September.

Still, **France** auctioned 20-, 30- and **50-year bonds in January and** investors then placed €23 billion of orders for an **inaugural** 22-year "**green**" **bond** from the country later that month, suggesting the **securities** are **still in high demand** from some quarters. **Proceeds** of the green bond **go toward environmentally friendly projects**.

French debt out to 5½ years in maturity yields less than zero, underlining the strength of the European Central Bank's stimulus and the impetus for investors to purchase longer-dated debt that is offering positive returns.

Political risks have also failed to shut some countries out of capital markets — a contrast to the height of the euro-zone's sovereign-debt crisis of 2010 to 2012. **Italian** bonds have been hammered as the chances have grown of **elections** later this year that could see the antiestablishment 5 Star Movement win a large slice of the vote. Even so, Italy managed to sell a 15-year bond in January.

Political risks have hardly affected the **Netherlands** despite coming **elections** in which another euro-skeptic party will be on the ballot. On Tuesday, the Dutch Treasury sold €5.7 billion in new 10-year bonds at a yield of 0.707%.

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A Nuclear Giant Powers Down

by Russell Gold and Mayumi Negishi — WSJ — Mar. 29, 2017
Matt Jarzemsky and Peg Brickley contributed to this article.

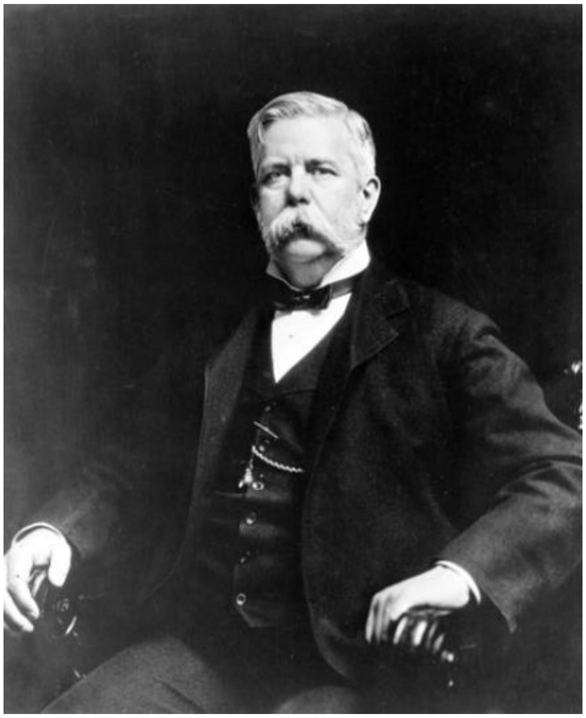
Chapter 11 raises questions about the fate of four half-finished nuclear reactors in the U.S.

Westinghouse Electric Co. filed for chapter 11 bankruptcy protection Wednesday, setting off a showdown between the nuclear power company's Japanese parent and a major U.S. utility, and threatening to drive a wedge between governments of two countries over the fate of industries each considers vital.

Westinghouse had incurred billions in cost overruns related to four nuclear reactors it is building in the southeastern U.S. The **runaway costs from the half-finished reactors threatened the viability of its Japanese parent company, Toshiba** Corp., whose precarious finances have attracted the attention of Japan's government. "This is a **de facto withdrawal from the overseas nuclear business** for us. Therefore, we don't see any more risk," Toshiba Chief Executive Satoshi Tsunakawa said on Wednesday.

But Toshiba now faces an **angry customer** in Tom Fanning, the CEO of **Southern Co**., the Atlanta power company and **primary owner of two of the reactors being built in Georgia.**

Mr. Fanning on Wednesday characterized the completion of the reactors as an international political issue, calling it a test of Prime Minister Shinzo Abe's commitments with President Donald Trump at a summit in February to help create American jobs.



Left: Westinghouse, an Electricity Pioneer ***1886**, **George Westinghouse**, an American inventor, **starts Westinghouse Electric** to sell **alternating-current power systems**. After 130 years, Westinghouse Electric's future is at risk because it suffered big cost overruns on U.S. nuclear-reactor projects.*

In an interview in Tokyo, Mr. Fanning said that Toshiba's commitments "are not just financial and operational, but there are moral commitments as well." He was in Japan, after the filing, to lobby for a resolution to the mounting dispute.

Mr. Fanning has said there are 5,000 jobs at stake at the two Georgia reactors that could be lost if Toshiba doesn't commit to paying billions in future costs to finish the reactors. **Westinghouse designed the reactors and is building them for Southern, and contractually had agreed to shoulder cost overruns**.

Scana Corp.—the company for which Westinghouse is building the **other two reactors in South Carolina** — said Wednesday for the first time that it **would consider abandoning them if costs changed dramatically**.

Left: ***2006, Toshiba of Japan buys Westinghouse Electric for $5.4 billion**. British Nuclear Fuels Chief Executive Mike Parker, left, and Toshiba President Atsutoshi Nishida, right, sign the paperwork.*

Trump administration officials were largely quiet on the bankruptcy Wednesday. The **Energy Department,** which has **provided** an $**8 billion loan guarantee for the Georgia reactors**, said it was in discussions with the companies involved. "We are keenly interested in the bankruptcy proceedings and what they mean for taxpayers and the nation," said Lindsey Geisler, an agency spokeswoman.

A Japanese government official said the U.S. hadn't raised Mr. Fanning's complaints with the Abe administration and that there had been no request for help to keep the projects alive.

*Left: **2012**, U.S. regulators **approve** Southern Co.'s **application to build two nuclear reactors** developed by Westinghouse at the **Vogtle** site near Waynesboro, **Ga***

"This is a private company's business and operation," the person said.

Based on a new Westinghouse design, the **reactors**, the **first** to be **constructed in** the **U.S. in nearly four decades**, were **supposed** to **be** an **answer to cost overruns and delays** that have dogged the nuclear power industry.

But already these plants are **years behind schedule** and have caused **huge losses** for Toshiba. Toshiba said it expected to suffer losses of **about $9 billion in the fiscal year ending March 31**, largely because it **guaranteed** nearly $**6 billion** in **Westinghouse's obligations to Southern and Scana**.

After the bankruptcy filing, Southern and Scana separately said they would finance continued construction of the reactors for 30 days, but the companies weren't clear where construction funding would come from after that time.

*Left: **2017**, **Toshiba** says it will record more than **$6 billion** in **write-downs** because of cost **overruns** on Westinghouse nuclear projects **in** the **U.S.,** and **President Satoshi Tsunakawa**, shown bowing at a March 14 news conference, says Westinghouse is considering a bankruptcy filing*

Mr. Fanning, who said he has spoken to Vice President Mike Pence, Commerce Secretary Wilbur Ross and Energy Secretary Rick Perry about the importance of completing the reactors, argued that more was at stake economically than the direct future of the facilities. "Westinghouse declaring bankruptcy has national security implications," Mr. Fanning said.

Toshiba's Woes at Nucler Subsidiary Westinghouse: Toshiba was looking to profit from a global nuclear power revival when it paid $5.4 billion for Westinghouse Electric in 2006. Instead, cost overruns and missed deadlines threaten to sink the Japanese conglomerate.

He said the estimated cost of the entire project was roughly $16 billion but cautioned that Southern was unsure of how much more was needed to finish the partially built reactors. The current target dates for completion of the Georgia reactors are 2019 and 2020, three years behind the original schedule.

Richard Nephew, a fellow at the Center on Global Energy Policy at Columbia University, said Mr. Fanning appeared to be using to his advantage the Trump administration's reputation for defending U.S. jobs and taking a tough stance even with allies.

"This is someone who knows what the triggers are for this administration," Mr. Nephew said of the CEO. "Everyone now has a sense of what the president's triggers are and I wouldn't be surprised if a lot of companies use those triggers to gain an advantage in negotiations with foreign companies."

The bankruptcy filing will likely cast a pall over future nuclear projects.

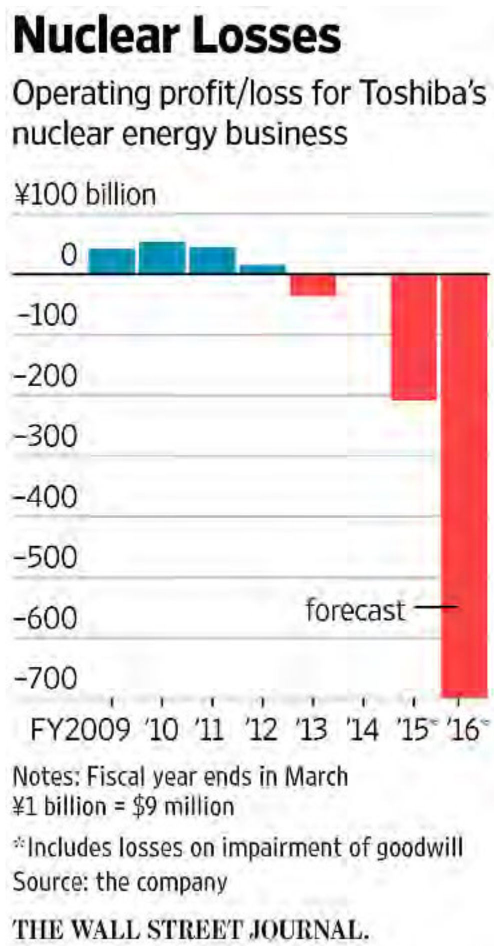
Mycle Schneider, a Paris-based independent consultant on nuclear and energy policy, noted that **Westinghouse is just the latest global nuclear builder to pull back or run into deep problems**. He pointed to **Siemens** AG's **decision to abandon the industry**, **Areva** SA's **financial and safety problems**, the **falling market value of China General Nuclear Power Group** and the **junk-bond status of Russia's Atomenergoprom** as evidence of turmoil in the business.

In bankruptcy filings, Westinghouse said it obtained $800 million in debtor-in-possession financing, allowing it to continue operations.

"I don't see how this can mean anything but even **greater cost growth for the plants under construction and an unacceptable risk for any that are under**

consideration," said Fred Beach, assistant director of the Energy Institute at the University of Texas at Austin.

Westinghouse was one of the **originators** of the **nuclear power age**, building the world's first commercial nuclear reactor **60 years ago**. Its pressurized water reactor design is in **430 power plants** and **accounts for 10% of electricity generated in the world**. Westinghouse **hopes to** emerge from bankruptcy proceedings as a company **focused on servicing existing reactors**, **selling fuel rods** and **decommissioning retired plan**ts. The bankruptcy filing referred to these businesses as "very profitable.



A person familiar with Toshiba's planning said earlier this week, before the bankruptcy filing, that Toshiba hoped Korea Electric Power Corp., known as Kepco, which is building a reactor in the United Arab Emirates, could emerge as an interested buyer. A Kepco spokesman said: "We have received no official offer from Toshiba. If any offer comes, we will put it under careful review."

The potential for nurturing a nuclear industry, fed by a renaissance of new plants, is dimming.

Edwin Lyman, who tracks the nuclear industry for the Union of Concerned Scientists, a nuclear-energy watchdog, said a government interested in pollution-free power could still build nuclear plants, but no one should assume it can be done more cheaply than other power sources or underestimate the potential problems that can occur. "If a government wants nuclear power, it is going to have to pay for it," he said.

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Record Bond Issuance Shows Many Investors Still Doubt Economic Growth

by Ben Eisen, Chris Dieterich and Sam Goldarb — WSJ — Apr. 9, 2017

Investors are buying record volumes of new bonds, signaling that many remain skeptical about the prospects for faster economic growth and are reluctant to move on from a strategy that has worked for years.

Companies and governments in emerging markets sold $178.5 billion of dollar-denominated debt in the first three months of the year, the best first quarter on record, according to data provider Dealogic. U.S. companies with junk-bond ratings issued $79.6 billion, double from a year earlier.

Highly rated U.S. companies also issued $414.5 billion of debt during the first three months of the year. That was a record for any quarter.

The booming debt sales reflect a strong investor appetite for higher-yielding bonds as the U.S. economy lumbers toward its ninth year of expansion but remains in slow-growth mode. These bonds offer more yield than low-risk government bonds, in which rates have rarely been lower. They also are viewed as less risky than stocks, especially by investors who consider valuations stretched.

“The old trade has worked really well, so you need overwhelming evidence before people will abandon something that has worked,” said Mohamed El-Erian, chief economic adviser at Allianz SE.

The hunt for yield appeared to be falling out of favor right after the presidential election. Investors bid up stocks, commodities and other riskier assets geared to global growth, betting that President Donald Trump’s stimulus plans would boost the economy. Consumer sentiment climbed to its highest in more than a decade, according to the University of Michigan.

Better growth could lead to higher inflation and tighter monetary policy, both of which are the main threats to the value of bonds because they erode the fixed returns over time.

Investors fled bonds, worried that a more-than-three-decade rally was ending. Bond mutual and exchange-traded funds world-wide saw $18.1 billion in outflows during the week after Mr. Trump’s election, the largest exodus since May 2013, according to fund tracker EPFR Global. Another $22 billion moved out of bonds over the next five weeks.

But that proved to be a blip before bond investors returned forcefully this year. They have pumped more than $112 billion into bond funds since the end of December through April 5.

The strong appetite for bonds shows how hard it is for investors to shake the assumption that the economy can do any better than muddle along as it has for years, with U.S. real gross domestic product growing less than 3% a year.

Lackluster growth also would likely mean the Federal Reserve would keep interest rates relatively low, economists say. That belief was reinforced when the U.S. Labor Department on Friday reported that nonfarm payrolls rose by only 98,000 in March, a slowdown from earlier this year.

The yield grab hasn’t just been in bonds. **Also rising have been stocks prized for paying dividend income that is more attractive when rates are low. Shares of S&P 500 utility companies have climbed 5.1% over the past three months**, second only to rapidly growing technology shares.

Investors poured a net $2.5 billion into U.S. junk-bond funds in the week ended Wednesday, the most since December. Emerging-market debt funds have collected new money for 10 consecutive weeks, according to Bank of America Merrill Lynch. Meanwhile, U.S. stock funds had $14.5 billion of outflows during that week, the most in well over a year.

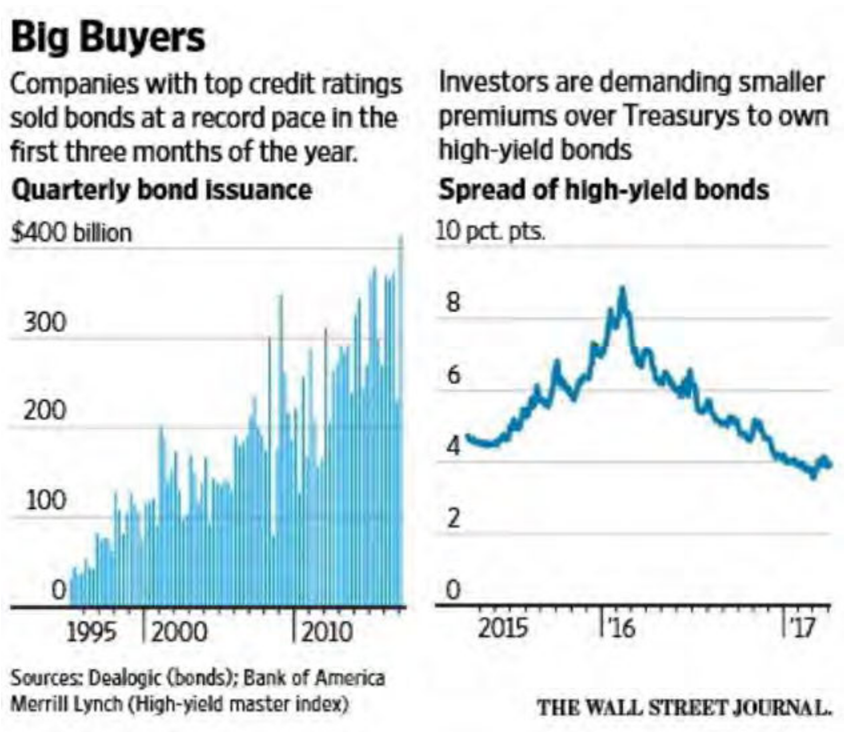
A definitive exit from the current low-rate environment seems “several years down the road,” said Steven Oh, global head of credit and fixed income at PineBridge Investments.

That backdrop has investors willing to pay lofty prices for riskier debt, even if it has bottom-of-the-barrel credit ratings. BWAY Holding Co, a privately owned maker of plastic and metal containers, sold $2.7 billion of bonds last month to help fund an acquisition. BWAY was able to sell eight-year unsecured bonds with a 7.25% interest rate despite its low junk rating.

That is “extremely aggressive” for a company with its financial profile, Mr. Oh said.

A spokesman for BWAY declined to comment.

Investors demanded 3.93 percentage points more than going Treasury rates to own high-yield bonds, according to Bank of America Merrill Lynch index data. That is less than half the spread in February 2016, when the stock market bottomed after a selloff.



Some investors think the hunt for yield is on borrowed time and could fall flat if economic growth either accelerates or drops off dramatically.

Unconventional monetary policy of super low or negative interest rates in much of the developed world is being “stretched to its limits,” Mr. El-Erian wrote last year. There could be faster growth if governments enact fiscal policies that stimulate their economies, he said, or there could a drop-off in growth that might lead to recession if these policy efforts fail.

Those who think the economy may be heating up say inflation could lead to higher rates. The Fed’s preferred measure of inflation, the personal-consumption expenditures price index, topped the central bank's 2% target for the first time in five years in February. Inflation would diminish the value of outstanding bonds.

But if the economy falls into recession, that would also be a problem for bonds. Negative growth would hurt corporate balance sheets, spurring waves of defaults and outflows from bond funds.

David Lafferty, chief investment strategist at Natixis Global Asset Management, contends that retirement-age investors and pension funds will provide steady demand for bonds. That demand could ease any selloff in the bond market even as the Fed aims to ratchet rates higher in the years ahead.

"There is this theory that once rates go back up that investors will have this big rotation out of bonds and into stocks," Mr. Lafferty said. "What that misses is that the bond market has a built-in, self-correcting mechanism which is that as yields back up, they become more attractive to more investors."

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Bonds Make a Comeback

by Min Zeng — WSJ — Mar. 27, 2017

U.S. government bonds rally as traders become skeptical the Trump administration will boost the pace of U.S. growth. U.S. government bond prices have rallied in recent weeks, sending yields sharply lower.

U.S. Treasury Building in Washington,

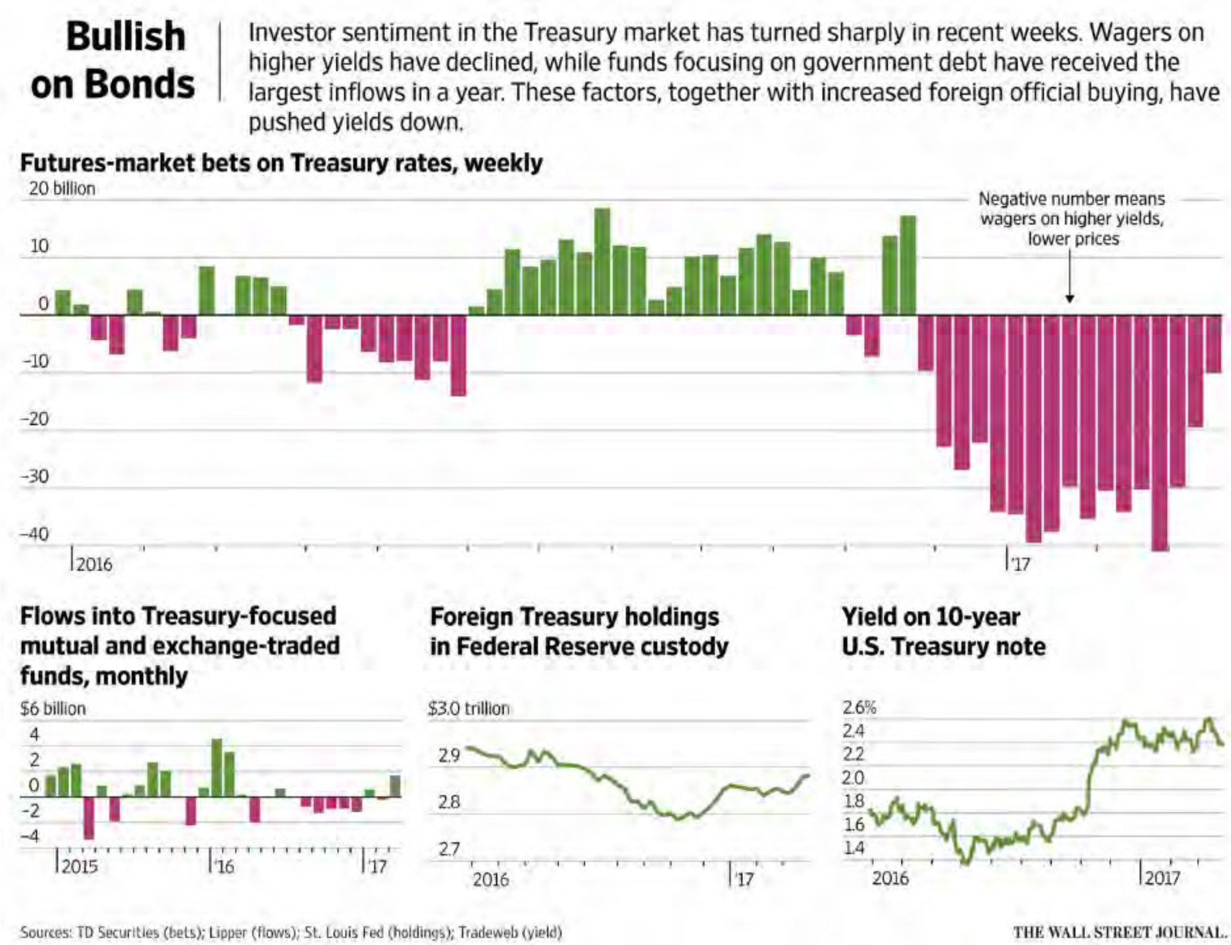
Government bonds are back in fashion, as the "**Trump trade**" **on higher growth and inflation begins to unravel**.

The **yield on the benchmark 10-year Treasury note tumbled to 2.373% Monday from a two-year high of 2.609% on March 13 and 2.446% at the end of last year**. Yields fall as bond prices rise.

The two-week-long Treasury rally corresponds with a modest pullback in stocks and the unwinding of market bets the Trump administration's economic policy would boost the pace of U.S. growth. The Dow Jones Industrial Average fell 45.74 points Monday to 20551, its 10th decline in the last 11 sessions.

The bond buying reflects concerns about the timing of a fiscal stimulus and tax cut plans after the political demise last week of a Republican bill to replace Obamacare as well as the relative attractiveness of bonds featuring higher yields. Foreign central bank holdings of U.S. government debt via the Federal Reserve's custody account reached a seven-month high last week, a noteworthy shift because official accounts had in recent months been large sellers of U.S. debt.

"Treasury bonds offer a healthy yield pickup versus other global rates markets, even still to this day,'' said George Goncalves, head of fixed-income strategy in the Americas for Nomura Securities International. "Central banks are long-term investors and are all about seeking Treasurys when they clearly offered value."



Bets on higher bond yields have been falling. Unwinding these so-called shorts requires investors and traders to return to the bond market as buyers, driving yields lower. Hedge funds and money managers accumulated a net $10 billion worth of shorts for the week that ended March 21, via 10-year Treasury futures, according to TD Securities. That was down from $41 billion at the end of February.

A $26 billion sale of two-year Treasury notes on Monday attracted 53.6% indirect bidding. A proxy of foreign demand including that from central banks, it was the highest since February 2016. A 10-year Treasury auction earlier this month also drew strong indirect bidding, with overall demand hitting the highest since last June.

Another big factor boosting Treasury holdings by central banks, analysts said, is the **U.S. dollar's break from its multiyear bull run**. On Monday, the ICE dollar index, a measure of the dollar's value against a number of its main rivals, hit the lowest since November. At the start of this year, it had jumped to the highest since 2002.

A weakening dollar has been pushing up the value of many emerging-market currencies including the Chinese yuan, which eases the burden of central banks in these countries to sell Treasurys to curtail local currencies' weakness and capital outflows. The dollar was down about 2% against the yuan traded outside mainland China.

China's central bank has been at the forefront in selling Treasurys after a large one-off devaluation of the Chinese yuan in August 2015 raised market expectations of a weakening yuan.

With the yuan stabilizing over the past few months and China's measures to curb capital outflows, the second-largest foreign owner of Treasury bonds after Japan has some breathing room. China's foreign exchange reserves rose in February, snapping an eight-month decline.

Effective capital controls and some stabilization in the dollar suggest that China "doesn't have to sell as much Treasurys to defend its currency,'' said Alejandra Grindal, senior international economist at Ned Davis Research.

China's Treasury holdings of all maturities fell by $168 billion between July 2016 and this January, according to the latest capital flow data from the Treasury, which is released with a two-month lag. Over the same period, Thailand's holdings rose by $24 billion, Korea's by $9.7 billion, Australia's by $6 billion and Brazil's by $3.6 billion.

In emerging economies, reserve levels have stabilized after two years of big declines. **Two-thirds of the 30 biggest emerging markets increased reserves last year**, according to Fitch Ratings.

Brad Setser, a senior fellow at the Council on Foreign Relations who specializes in global capital flows and central bank reserves, said he is "not confident" that the tide of foreign central banks selling Treasurys has ebbed.

Mr. Setser said actions by foreign central banks hinges on "the trajectory of the dollar." If the dollar rallies again, it would put pressure on China and some other emerging market countries to sell Treasurys, he said.

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Can Trump Deliver 3% Growth?
Stubborn Realities Stand in the Way

by Nick Timiraos and Andrew Tangel – WSJ – May 15, 2017
Suzanne Kapner contributed to this article

Workers at an Ariens Co. factory in Wisconsin

Ariens Co., a maker of lawnmowers and snow-blowers, faces a bottleneck in its plans to raise production 40%. It can't find enough workers.

The Brillion, Wis., company bused some Somali refugees from nearby Green Bay to help, but they weren't enough, and it is spending up to $15,000 a month on recruiting.

"We see the demand right in front us," said Chief Executive Dan Ariens. "It's very frustrating."

His lament points to an issue at the heart of President Donald Trump's economic agenda. The president has laid out a goal of getting the U.S. economy, which has expanded at less than a 2% average rate for the past decade, to grow at above a 3% rate over the long term.

Two stubborn obstacles stand in his way. The **work force isn't producing enough new workers**, **and** the **productivity of those working isn't growing fast enough**.

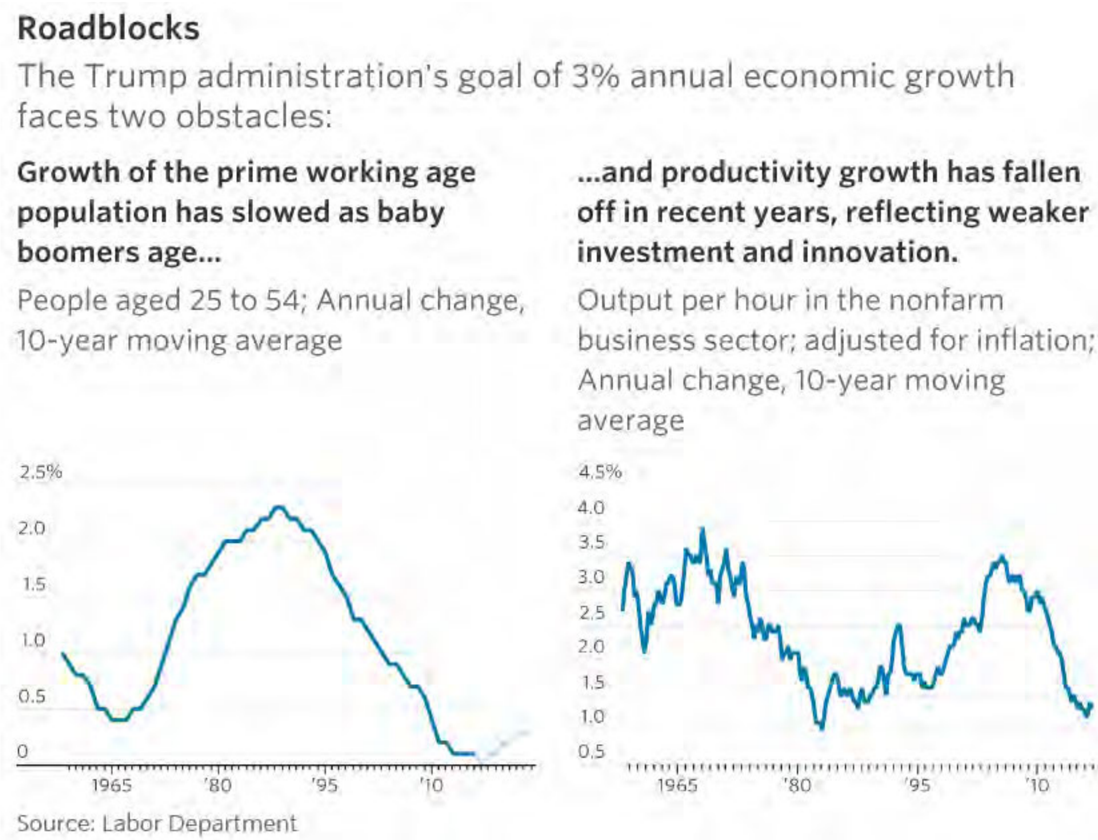
In the long term, an economy can't expand faster than the combined growth rates of its working population and their output per hour. That combined number, in many economists' projections for the next decade, is about 1.8%. This is also the long-run growth rate projected for the economy by Federal Reserve officials.

Mr. Trump's advisers say their policies can deliver 3% to 4% growth year after year, the kind of prosperity the U.S. saw during the 1980s and 1990s — in effect expanding what is considered the economy's long-term potential.

A note on a framed newspaper article in Treasury Secretary Steven Mnuchin's office is even more ambitious. The article announced his Cabinet selection, and Mr. Trump signed it in felt-tip pen with the added note "5% GDP."

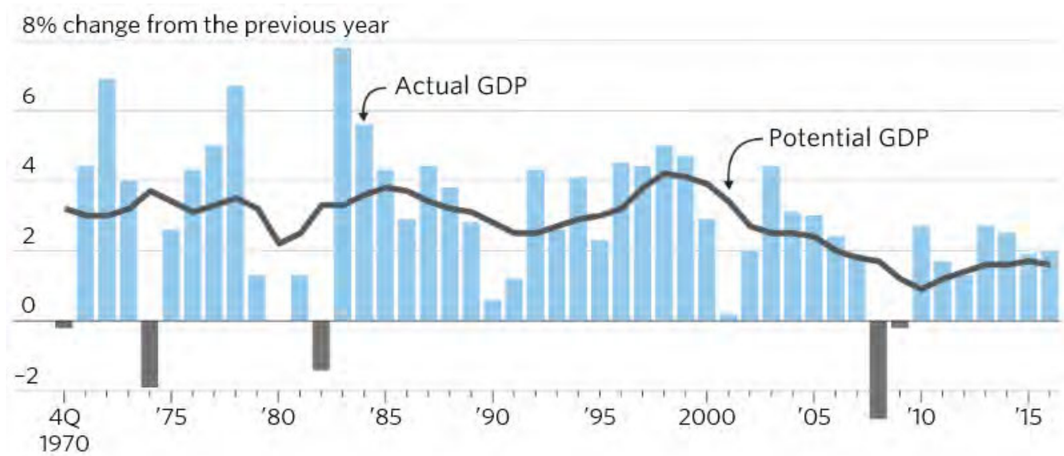
Faster growth could push up household incomes, which are stuck below their 1999 peak when adjusted for inflation. Such growth would also make it easier for the administration to secure large cuts in corporate and individual tax rates, boost military spending, and maintain Social Security and Medicare without running larger deficits.

Asked in April about potentially higher deficits from rate cuts in the tax plan, Mr. Mnuchin said, “The plan will pay for itself with growth.”



The Economy's Speed Limit

Economists calculate potential gross domestic product, essentially the economy's maximum sustainable output, from growth in the potential workforce and in productivity. Actual GDP can fall short in a recession when output is weak or exceed potential during a recovery, but over the long run they tend to grow together.



Sources: Commerce Department (actual figures); Congressional Budget Office (potential GDP)

If the economy expands at around a 3% rate over the next decade—a projection Mr. Mnuchin says the administration will make in its budget proposal later this month—government revenue over that time should be $3.7 trillion more than currently forecast, according to estimates by economists at Goldman Sachs Group Inc. The projection assumes no change in tax rates.

That would be enough money to build 292 aircraft carriers. It would fund 28 million additional months of Social Security payments for the average beneficiary.

Mr. Trump wants to spur the economy partly by improving the nation's trade position. Less red tape could help business operate more efficiently. A tax overhaul could give companies more incentive to invest and give individuals more desire to work, not to mention more disposable income to shop with.

Trump advisers also are hopeful that improved confidence and short-term economic news would spur capital spending that makes business more productive.

Finding the labor for this higher-functioning economy could be a challenge. **Over the past decade, the population aged 25 to 54, known as the prime age, has been growing at just 0.1% annually**. **When the U.S. had consistent 3% economic growth in the 1980s, the prime-age population was expanding at a brisk 2.2% rate, thanks to the post-World War II baby boom**.

Work-force participation rates, meanwhile, have flattened out lately for women and declined for decades among men.

At Macy's Inc., Chief Executive and President Jeff Gennette hit on a plan for growth with a 2015 agreement with Luxottica Group SpA to open LensCrafters shops in department stores. The plan is hobbled by a shortage of optometrists. "We are taking all of the graduating classes right now, and it is going to take us a full year to…satisfy the expansion that we have," Mr. Gennette said at a retail conference.

Without faster growth in workers, the labor force would need to churn out goods and services much more productively to give the economy room to grow at a 3%-a-year rate over an extended period. The trend is the opposite. **Workers' output per hour in the nonfarm business sector has been increasing only by 0.7% a year since 2010**.

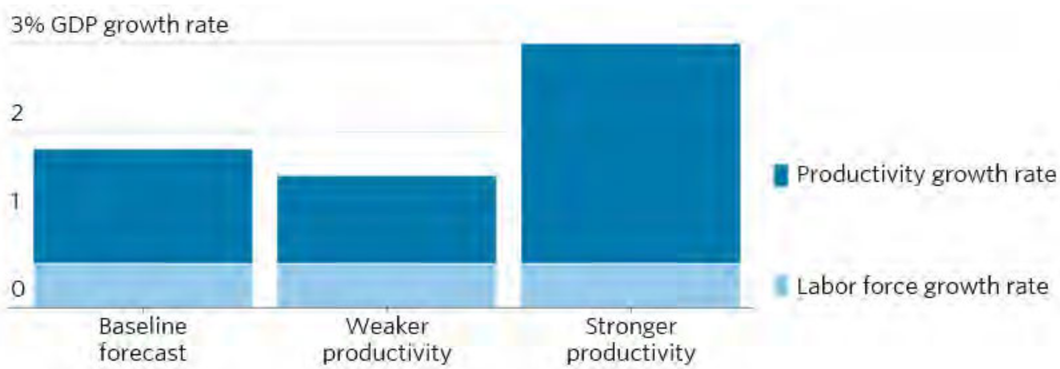
Many economists see that picking up in coming months, perhaps doubling. Meeting Mr. Trump's objective, though, would need "the type of growth we often refer to as productivity miracles," said Michael Feroli, chief U.S. economist at J.P. Morgan Chase & Co.

The contours of growth and the labor market are likely to influence the pace by which the Fed drains its easy money from the financial system. If growth advances and productivity does too, policy makers may be able to **keep interest rates lower for longer** because productivity growth holds down inflation. Companies can boost profit margins and hold down costs, and thus inflation, when they can produce more goods and services with fewer workers.

If, on the other hand, the administration's policies boost demand without drawing in new workers or raising their productivity, the growth that results could be harder to sustain because it would produce inflation. The Fed would feel additional pressure to raise interest rates to prevent the economy from overheating.

Limits of Growth

The **U.S. economy's potential long-term growth rate is limited to the sum of workforce growth and productivity growth**. The **workforce is projected* to expand at 0.5% annually over the next decade and productivity at 1.3%, for growth of 1.8%.** Also pictured are alternatives for productivity growth—slowing to the 10th percentile of its historical average† or booming to the 90th percentile of that average.



*Forecast from the Congressional Budget Office †Since 1958

Sources: Congressional Budget Office (baseline forecast, workforce projections); Jason Furman of the Peterson Institute for International Economics (productivity projections)

With the unemployment rate now at 4.4% and operating at a level economists consider to be "full employment," meaning the economy produces as many jobs as it can without spurring inflation, the labor market provides little room for the kind of economic surge that marked the 1980s.

"Strong growth during the Reagan years was driving unemployment from 10% to full employment. We can't do that trick again," said Joel Prakken, senior managing director of Macroeconomic Advisers, a forecasting firm.

The Trump administration has faced internal tensions over its growth forecast. Officials ultimately settled on economic growth forecasts in its upcoming budget proposal to Congress that will show the **economy reaching 3% growth after two years**, **according to Mr. Mnuchin**.

The president is pushing some policies that work against economic growth. **Relatively low birthrates and an aging population mean immigration is the source of nearly all of the work force's net increase, so its growth rate would be even lower if legal immigration were curbed**. That makes boosting productivity all the more important if the economy is to get onto a faster growth plane.

Home builders are wrestling with both issues. The **real-estate crisis a decade ago washed many skilled workers out the construction labor force**. At Camden Property Trust, this dearth has extended the time it takes to build a low-rise apartment complex to 24 months from 18.

"I'm often paying unskilled workers more money, and I have to pay someone else to come in and fix crooked walls and moldings and cabinets that don't connect," said CEO Ric Campo of Camden, which operates in 16 markets and is based in Houston.

Camden uses efficiencies such as prefabricated concrete building panels and roof trusses, "but there hasn't been a huge breakthrough yet where we can lower costs dramatically," said Mr. Campo. "You have a nail gun instead of a hammer, OK? But you still have to line it up and pull the trigger."

Productivity in construction has contracted at a 1% annual rate since 1995, according to a study by McKinsey Global Institute, the research arm of McKinsey & Co., due in part to reliance on unskilled workers and in part to government red tape.

Joel Shine, chief executive of builder Woodside Homes Inc., visited Kyoto, Japan, to see how firms there use automation in home construction. He thinks it would take at least a decade for the innovations to become mainstream in the U.S., in part because they would require building-code changes.

Woodside Homes CEO Joel Shine visited Japan to check out productive building techniques

State and local rules often play as big a role for his business as the federal government. Higher permitting fees, for instance, have raised construction costs in California towns. "There are a lot of places if you gave me a raw lot for free — for free! — I could not even come close to building an entry-level house," Mr. Shine said.

Immigration restrictions would make growth harder, he added. "We're somewhat uniquely capable of helping the administration get to where they want to go, but they can't ask us to do that and then make immigration impossible," Mr. Shine said.

White House Budget Director Mick Mulvaney, who once ran his family's real-estate business, **disputed that premise and pointed to millions of prime-age workers who aren't in the labor force**. "If you created economic opportunity and jobs that they want, they would come back," Mr. Mulvaney said. "So I'm not worried about the tightness of the labor supply."

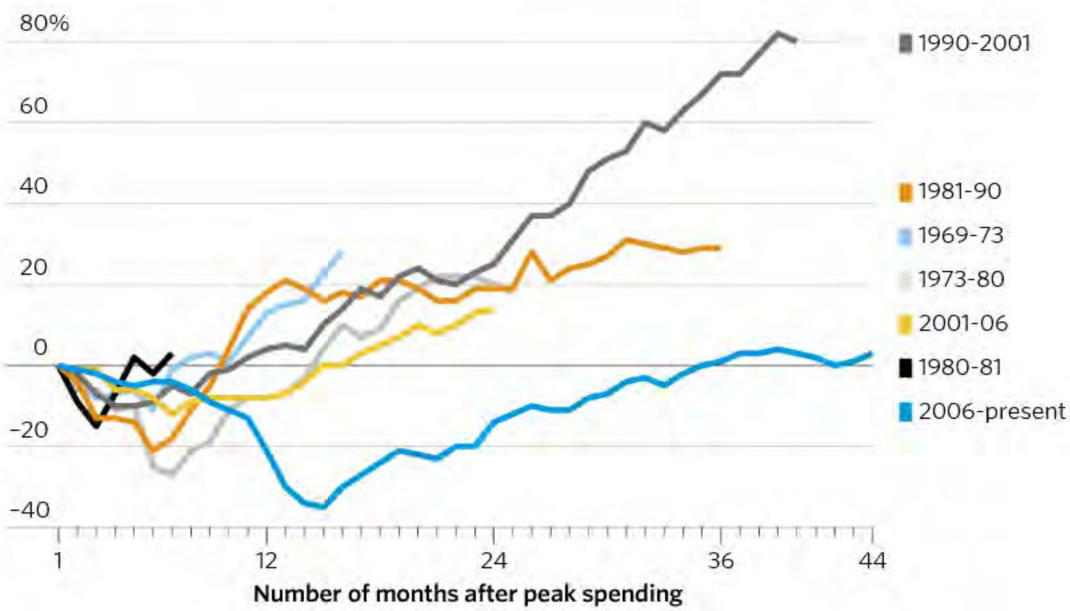
If that proves insufficient, the onus will be on productivity. It isn't easy either to measure or to predict. The U.S. economy enjoyed a boom in productivity from around 1995 through 2004, a spurt few economists foresaw. By 2003, the conventional wisdom had reversed and economists polled by The Wall Street Journal were expecting productivity growth to continue unimpeded. Instead, it slumped.

The weakness reflects a **sustained deceleration in the pace of innovation and investment**. Capital investment growth slowed sharply during and after the 2007-09 recession.

Goldman economists see evidence that the slowdown has been cyclical, driven by the financial crisis, and now could be changing. Mr. Ariens, the snow-blower executive, offers one bit of evidence. He plans to spend $9 million this year on factory upgrades, including advanced metal-stamping machines that could do the work of a dozen workers.

Low-Investment Recovery

Gross private domestic investment, which includes housing and business spending on structures and equipment, after last decade's recession has taken an unusually long time to rebound when compared to previous recoveries.



Source: Commerce Department

Some productivity optimists say gains from new technology will build in the years ahead. They see businesses incorporating a backlog of innovations in artificial intelligence, from self-driving vehicles to the processing of routine clerical work.

A paper from four growth specialists published by the Brookings Institution in March takes a dimmer view. It maintains that almost the entire shortfall in output during the recent expansion reflects long-term forces unrelated to the financial crisis and recession, including a drop in a measure of economic dynamism called "total factor productivity." That measure reflects how efficiently labor and capital are used.

Many economists say well-designed cuts in taxes and regulations could deliver a lift to the U.S. economy that would nudge growth to 3% for a year or two. They are less confident it could be sustained. Dale Jorgenson, a Harvard University economist who specializes in growth accounting, thinks that the economy should expand 1.8% annually over the next decade, but that a well-designed tax-code overhaul might boost the long-term growth rate to 2.4%.

"In some respects," said James Stock, a Harvard colleague and veteran of the Obama administration, "2.5% growth could be the new 4%, in that it would still be a significant accomplishment."

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Change in US Accounting for Pension Costs Provides Better View of Operating Profits

by Kevyn Dillow, VP & Senior Accounting Analyst; and
David Gonzales, VP & Senior Accounting Analyst
Moody's — Mar. 13, 2017

Last Friday, the US Accounting Board issued ASU 2017-07, which changes the classification of postemployment benefit expense on income statements. The change helps credit analysis by providing a more authentic view of operating income. Accounting for postemployment benefits is one of the more complex and opaque areas of accounting. After adoption of the new accounting standard, company reporting will require less manipulation and be more useful for financial analysis.

Legacy accounting treats pension and other postemployment benefit (**OPEB**) **expense as a single item**. **However, postemployment benefit expense includes many components, such as the cost of benefits earned during the period (service cost), interest on the projected benefit obligation and actuarial gains and losses from changes in assumptions or actual returns differing from expectations**.

The existing accounting presentation classifies total postemployment benefit expense as an operating expense on the income statement, but **only the service cost component is a true period expense**. Historically, we and many other financial analysts have manually adjusted the non-service cost components of pension expense out of operating income.

The change to presentation will bring reporting in line with our adjusted amounts. **Only service cost will be reported as an operating expense and the other components of postemployment benefit expense will be non-operating expenses**. This provision will not result in total expense changing, but will result in higher reported operating profits.

Approximately 50% of our US non-financial rated entities will be affected by the new rule. We estimate that if this accounting method were in place for 2015, operating profits would have been $20 billion higher from pension expense alone. We do not have accurate estimates for OPEB expenses, but companies with large pension plans usually have large OPEB plans, resulting in the effect on total operating profits being even higher when factoring in OPEB. Because we do not make adjustments for OPEB to US GAAP reporting companies, our **adjusted operating profit will increase**.

Top 20 US Rated Publicly Traded Non-financial Companies with Largest Change to Operating Expenses for 2015 Reporting Period, $ Thousands

Company	Non-Service Cost Component of Pension Expense for 2015	Percent Decrease to Operating Expenses	Reported Operating Profit for 2015	Recast 2015 Operating Profit, Excluding Non-service Component of Pension Expense
The Timken Company (Baa3 stable)	480,200	18.67%	-151,400	328,800
The Scripps E.W. Company (Ba2 stable)	69,063	9.57%	-82,872	-13,809
Kimberly-Clark Corporation (A2 stable)	1,394,000	8.21%	1,613,000	3,007,000
NCR Corporation (Ba3 stable)	452,000	7.32%	135,000	587,000
Energen Corporation (Ba3 stable)	31,320	6.96%	-1,437,851	-1,406,531
PTC Inc. (Ba2 stable)	72,410	6.38%	41,616	114,026
CSRA Inc. (Ba2 stable)	162,380	4.32%	187,343	349,723
Ashland LLC (Ba1 stable)	204,000	4.12%	435,000	639,000
Aerojet Rocketdyne Holdings, Inc. (B1 stable)	59,500	3.86%	102,600	162,100
Unisys Corporation (B2 negative)	100,000	3.26%	-55,100	44,900
Raytheon Company (A3 stable)	649,000	3.21%	3,013,000	3,662,000
General Electric Company (A1 stable)	3,031,000	3.17%	4,958,000	7,989,000
Potlatch Corporation (Ba1 stable)	14,750	2.86%	58,907	73,657
National Fuel Gas Company (Baa3 stable)	25,653	2.82%	-611,053	-585,400
Conagra Brands, Inc. (Baa2 stable)	281,166	2.61%	881,400	1,162,566
Brunswick Corporation (Baa3 stable)	94,000	2.55%	331,700	425,700
FedEx Corporation (Baa2 stable)	1,113,000	2.49%	3,077,000	4,190,000
Marathon Oil Corporation (Ba1 stable)	119,000	2.46%	-2,278,000	-2,159,000
Reynolds American Inc. (Baa3 positive)	152,000	2.24%	6,953,000	7,105,000
Pfizer Inc. (A1 stable)	708,000	2.20%	11,824,000	12,532,000

Source: Moody's Financial Metrics

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Economy Stumbles Despite Optimism

by Eric Morath — WSJ — Apr. 14, 2017
Suzanne Kapner and Mike Colias contributed to this article.

Households, businesses and investors **started the year** riding a wave of rising **expectations for growth** with a new, business-friendly president in the White House, but the euphoria **hasn't translated** quickly **into broad economic gains**.

Bank loan growth has slowed, economists have marked down projections for output growth, the stock market has lost some momentum and consumer spending is taking an anemic turn.

In the latest evidence, the Commerce Department reported Friday that sales at U.S. retail stores, restaurants and online sellers decreased 0.2% in March from the prior month. February sales were revised down to a 0.3% decrease from an initial estimate of a 0.1% gain. It marked the first consecutive declines for retail spending since the first two months of 2015.

"The market in the U.S. in particular continues to be challenged," Jerry Storch, chief executive of Saks Fifth Avenue and Lord & Taylor parent Hudson's Bay Co. , told investors earlier this month. "We're planning as if the environment is not going to improve." The retailer is looking to reduce costs in case sales don't improve.

Uneven retail spending stands in sharp contrast to soaring measures of consumer confidence. The University of Michigan's consumer-sentiment measure, released Thursday, is near the highest level in more than a decade, and the index's measure of current conditions touched the highest mark since 2000 in early April.

"The rising levels of confidence we've seen since the election hasn't translated," said Carl Tannenbaum, chief economist at Northern Trust. "Consumers are saying one thing in response to a survey, but doing something different with their wallet."

He said underlying fundamentals — chiefly job and wage growth —should support better spending later in the year, but he is not expecting a near-term spending breakout based on confidence figures.

Inflation unexpectedly weakened in March. The Labor Department's consumer-price index declined a seasonally adjusted 0.3% in March from the prior month, and prices excluding food and energy fell 0.1%, the agency said Friday. It was the first decline for those so-called core prices since January 2010 and the steepest drop for overall prices since January 2015. Slowing inflation pressures could be a sign that it is difficult for firms to pass along further price increases to consumers.

President Donald Trump, stung in recent weeks when an attempt to overhaul the Affordable Care Act stalled in Congress, has cited confidence surveys as evidence of economic momentum. "Economic confidence is soaring as we unleash the power of private sector job creation," he tweeted on Wednesday.

Hiring growth has largely backed up that view, though the broadest measure of economic growth due out later this month is likely to paint a different picture of the first months of 2017.

Many economists project the annualized pace of growth in the first quarter slowed from the 2.1% rate recorded in the final three months of 2016. **Following Friday's data release,** the **Federal Reserve Bank of Atlanta lowered its projection for first-quarter economic growth to a 0.5% pace**. **In early February, it expected better than 3% growth**. Forecasting firm **Macroeconomic Advisers forecasts a 0.6% advance for last quarter**.

Macroeconomic Advisers expects a rebound to a 3.6% growth pace for the second quarter. Still, **the slow start to the year could make it difficult for the economy to grow for all of 2017 much better than the roughly 2% pace recorded since mid-2009**.

Decreased spending at auto dealerships and gasoline stations were the primary drivers of the recent decline in overall outlays at retailers. Spending on vehicles and parts has fallen for three straight months, according to the Commerce Department, the longest streak of declines since 2008. The slowdown in car sales is a worry because they have been a driver of economic growth. U.S. car and light-truck sales hit a record high in 2016.

Dealership lots are swollen amid flattening demand following a record seven-year run of rising vehicle sales. Even with record-high discounts, U.S. dealerships in March carried 72 days' worth of inventory based on the current sales pace, up from 66 days a year earlier.

Tepid sedan sales are the primary reason for the inventory glut, as consumers gravitate toward SUVs and pickup trucks given low fuel prices. General Motors Co. is in the process of laying off about 4,400 workers as it curbs production across several Midwest plants, mostly at factories that make sedans.

Bank loan growth, meanwhile, is slowing markedly. Commercial and industrial loans from banks were up just 2.8% in late March from a year earlier, compared with average growth of 10% in a stretch between 2014 and 2016. Consumer loan growth was up 5.8%, a slowdown from earlier months though in line with average growth in the 2014-2016 periods.

Banks reporting earnings this week said one reason for the loan slowdown was that businesses were turning to booming bond markets for capital rather than tapping credit lines.

It is possible the first-quarter slowdown will quickly reverse itself. In several years of this expansion the economy started out on a slow footing only to pick up as the year progressed. In 2011 and 2014, for example, output contracted, sparking fears of recession. Bad weather and quirks in statistical seasonal adjustments were among the explanations. Worries about external events, including economic uncertainty in Europe and China, also have nagged at business and investor confidence.

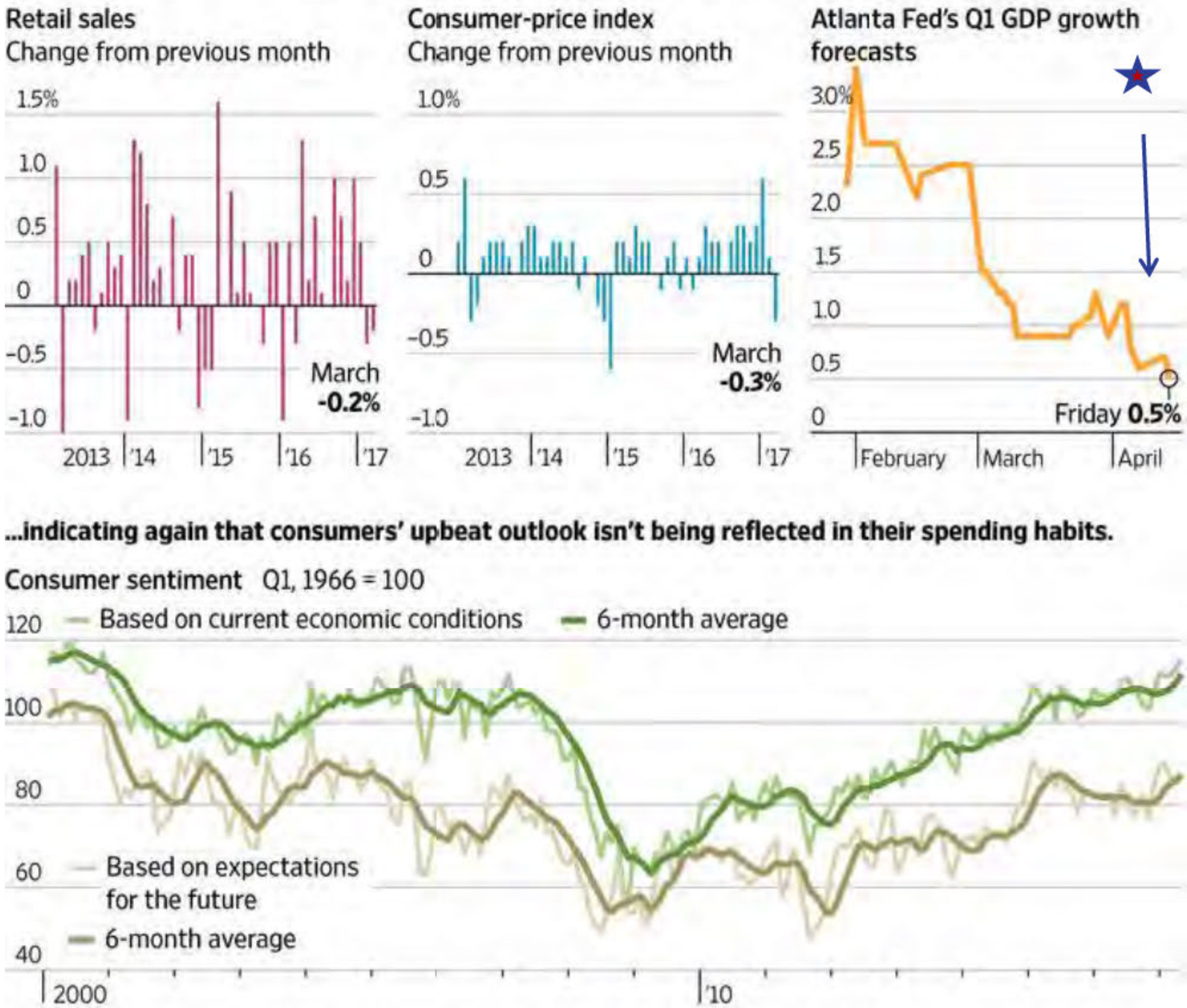
What is striking this year is that confidence started out the year on such a high note, with little obvious follow-through in spending.

Customers at Gazelle Sports, an athletic-apparel chain based in Kalamazoo, Mich., are snapping up more expensive running shoes and limited-edition items than they were a few years ago, said co-owner Chris Lampen-Crowell. But fewer shoppers are visiting his five stores. What is gone is the impulse purchase of a T-shirt by window shoppers.

Confident Consumers Fail to Spend

Economic data released Friday are at odds with rising consumer optimism.

Weak retail-sales and inflation figures point to an economy that decelerated early this year...



Sources: Commerce Department (retail sales) and Labor Department (CPI) via the Federal Reserve Bank of St. Louis; Federal Reserve Bank of Atlanta (GDP); University of Michigan via Haver Analytics (sentiment)

THE WALL STREET JOURNAL.

"People that walk in the door are confident," he said. "But people don't shop as social activity anymore — it's part of the move to online — younger people want to spend on entertainment."

The latest retail figures underscore consumers' shift to e-commerce platforms. Department-store sales rose 0.2% on the month, but were down 4.5% from a year earlier. Non-store retailers, a category that includes online shopping at outlets such as

Amazon, posted a 0.6% gain from the prior month and an 11.9% increase from a year earlier.

At least a dozen major retail chains filed for chapter 11 bankruptcy protection this year. That includes clothing seller Limited Stores LLC, which announced it would close all 250 of its stores, and Payless ShoeSource Inc., which is closing 400 stores in an effort to reorganize around smaller operations.

Among younger consumers, "the propensity to buy online shoots up and the willingness to go to brick-and-mortar stores starts declining," Wayfair Inc. Chief Executive Niraj Shah told investors last month. The online seller of home furnishings expects continued sales growth as more millennials get married and buy homes. The firm recently launched a wedding registry.

"You're talking about folks who grew up with digital technology, who've effectively been buying that way their whole adult life," he said.

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ComEd Calculates Historically Low 8.4% ROE in New FRP Case

by Russel Ernst — Regulatory Research Associates (RRA)
An Affiliate of SNL Financial and S&P Global Market Intelligence — Apr. 19, 2017

Exelon Corp. subsidiary Commonwealth Edison Co., or **ComEd**, proposes to implement a $99.9 million, or 3.6%, electric distribution revenue requirement increase in the context of its **annual formula rate plan**, or **FRP**, proceeding, which was filed on April 13. A final **Illinois Commerce Commission**, or **ICC**, decision in the case, Docket No. 17-0196, is expected by Dec. 13.

For the "filing year," **ComEd calculates an 8.4% ROE** using the parameters outlined in the FRP statute. The ROE to be used in FRP proceedings is calculated **using a formula** that is **tied to long-term Treasury Bond rates**, and the 8.4% equity return is significantly below the **9.6% average ROE authorized for electric utilities nationwide during 2016**, **excluding incentive returns authorized in limited issue rider proceedings**, as calculated by Regulatory Research Associates. The calculated ROE to be used in the instant case is among the **lowest equity returns** to be accorded an electric or natural gas utility nationwide **in at least 35 years**.

Commonwealth Edison
Electric distribution FRP case

Current case	Revenue change ($M)	ROE (%)	ROR (%)	Rate base value ($B)
Company request	99.9	8.4	6.47	9.662
Previous case 12/06/16	**Revenue change ($M)**	**ROE (%)**	**ROR (%)**	**Rate base value ($B)**
Company revised request	135.7	8.64	6.71	8.831
ICC authorized on rehearing	113.3	8.64	6.71	8.827

Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Key Aspects of FRP Statute

This case is ComEd's seventh FRP proceeding conducted under state law that requires ComEd and Ameren Corp. subsidiary Ameren Illinois Co., or AI, to invest specific amounts in their transmission and distribution systems over the years 2012 through 2021, with recovery of these investments to occur in the context of annual FRP proceedings, subject to ICC approval. The law requires ComEd to invest at least $1.3 billion over a five year period in certain modernization projects, and at least an additional $1.3 billion, over a 10-year period, on various distribution system upgrades. The ICC continues to have authority to investigate the "prudence and reasonableness" of all expenditures made in accordance with these investment programs and is required to render decisions on the annual FRP filings — see the Illinois Commission Profile.

The **FRP calculations**, among other things, **are to reflect the utility's actual capital structure, excluding goodwill; incorporate a formula for the purpose of calculating the allowed ROE** — application of a **580 basis point premium to the 12-month average 30-year Treasury Bond yield**; and reflect estimated net plant additions and depreciation through 12 months beyond the end of the test year. If, in the context of an FRP filing, the utility's actual ROE in a given period is more than 50 basis points above or below its authorized ROE, comprising the dead band ROE, the company would be required to refund to, or collect from, ratepayers any amounts outside of this dead-band. Each FRP also includes a true-up of post-test-year additions and operating costs to actual amounts.

In addition, the utility's allowed ROE may be reduced if the company fails to meet certain performance metrics. The statute calls for the ROE collar provisions to no longer apply beginning with the companies' FRP filings in 2018, and for the plans to terminate at year end 2022. Once the FRPs are terminated, ComEd and AI would be permitted to establish a "revenue balancing adjustment tariff," following ICC approval, to true up the companies' revenue requirements to the revenue requirements most recently approved by the commission.

Overview of Instant Request

The revenue requirement increase proposed by ComEd includes an $82 million filing year increase premised upon an 8.4% return on equity (45.89% of capital) and a 6.47% return on a $9.662 billion rate base. The filing reflects actual results for 2016, and estimated net plant additions through 2017. In addition, the proposed reduction includes an $84.1 million upward "reconciliation" adjustment, as required by the FRP statute, calculated using an 8.34% return on equity (45.89% of capital) and a 6.45% return on an $8.807 billion rate base, to reconcile the company's actual 2016 revenues with the level that would have been approved had actual data been available at the time rates were established.

Because the $84.1 million reconciliation adjustment for 2016 was larger than the $60.8 million adjustment approved, on rehearing, for 2015, the upward reconciliation adjustment proposed in the instant case is effectively $23.4 million. ComEd did not calculate a dead-band ROE adjustment, as the company's 8.8% earned ROE calculated for 2016 was within the 7.84% to 8.84% dead-band established for the year under the FRP provisions. In aggregate, the revenue requirement increase sought by ComEd is $99.9 million.

The ROE used to calculate the reconciliation adjustment includes a six-basis-point penalty to reflect ComEd's failure to attain certain performance metrics.

Previous Proceeding

ComEd's previous FRP case, Docket No. 16-0259, was decided in **December 2016**, when the ICC authorized the company a $130.9 million revenue requirement increase that included a $137.4 million filing year increase, premised upon an **8.64% return on equity** (45.62% of capital) and a 6.71% return on an $8.831 billion rate base, and an effective downward reconciliation adjustment of $13.7 million. The ROE used to calculate the reconciliation adjustment included a 5-basis-point penalty to reflect ComEd's failure to attain certain performance metrics. The ICC also calculated a $7.1 million upward dead-band ROE adjustment.

On rehearing, the commission authorized the company a revised $113.3 million revenue requirement increase, reflecting certain adjustments that were made to recoverable costs associated with safety standards required by the Occupational Health and Safety Administration.

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Falling Yields Highlight ‘Show-Me’ Sentiment on U.S. Policy

by Sam Goldfarb and Min Zeng — WSJ — April 13, 2017

Many investors entered 2017 expecting Treasury yields would rise to around 3% by year’s end, reflecting economic growth and presumed success in cutting taxes and regulation.

President Donald **Trump** addresses a press conference **Wednesday**. In an interview with The Wall Street Journal, Mr. Trump **said** he **favored** a **weaker dollar and low interest rates**, **pushing down the yield on 10-year U.S. Treasury notes.**

Government-bond yields are falling, the latest sign that **investors are retreating from expectations that favorable government policies would deliver a welcome jolt to global growth, inflation and interest rates**.

The yield on the benchmark **10-year U.S. Treasury note** fell Thursday to 2.237%, marking its lowest close since Nov. 16 and its **largest one-week drop since last June**. That was down from 2.294% at its 3 p.m. settlement Wednesday and 2.609% on March 13. Yields fall as bond prices rise.

The **decline is noteworthy because it takes the yield below the 2.3%-2.6% range that took hold soon after Donald Trump was elected president in November**. U.S. markets are closed Friday in observance of Good Friday.

Many investors entered 2017 expecting the yield would rise to around 3% by the end of the year, reflecting economic growth and the administration's presumed success in cutting taxes and reducing regulation. Rising interest rates on bonds often reflect faster growth as investors demand better returns to compensate for higher short-term interest rates set by the Federal Reserve and inflation.

Instead, **yields are again falling from relatively low levels**, **raising fresh concerns about the health of the global economy** years after the financial crisis and present valuations of stocks, bonds and other assets.

"The **Trump trade is fading** as the complexities of implementing the Trump agenda have become gradually understood,'' said Christopher Sullivan, chief investment officer at the United Nations Federal Credit Union.

The bond rally isn't the only market development reflecting a shift in investors' thinking. Both the Dow Jones Industrial Average and the S&P 500 have pulled back after hitting records in early March. Bank shares, a big post-election winner, have lagged this year, with the sector declining again Thursday despite generally solid earnings from Citigroup Inc., J.P. Morgan Chase & Co. and Wells Fargo & Co. **Shares in utilities**, the laggard late last year, have **rallied in 2017**.

The Mexican peso has almost recouped all of the ground it lost against the dollar in the aftermath of the U.S. election. Gold, meanwhile, has regained a large part of its post-election selloff and is up 11.8% this year.

The 10-year yield began to decline when **Fed** officials signaled after their March 14-15 policy meeting that they still expect to raise interest rates three times this year. That was a **less aggressive message than many investors had expected** and was followed quickly by a setback for Mr. Trump when he failed to gather enough votes to pass a health-care bill.

Tighter monetary policy tends to raise interest rates on new bonds, diminishing the value of outstanding debt that pay less. Faster growth can lead to higher inflation, which chips away at the value of bonds' fixed payments over time.

Bonds got an extra boost this week from geopolitical developments, including rising **tensions between the U.S. and Russia** over the Syrian conflict and between the U.S. and **North Korea** amid efforts to thwart that country's nuclear development ambitions.

Investors have also become increasingly concerned about the state of **France's presidential election**, where two of the four leading candidates are deeply skeptical of the European Union.

Then Mr. **Trump** on Wednesday said in an **interview with The Wall Street Journal** that he **favored** a **weaker dollar** and **low interest rates**, **pushing** the **10-year yield as low as 2.218% in overnight trading.**

Some investors focused on Mr. Trump's reversals on several policies, arguing they raised questions about his commitment to campaign promises. After previously saying there was little chance that he would re-nominate Federal Reserve Chairwoman Janet Yellen when her term runs out next year, he said Wednesday that he was open to the possibility. He also said he now supports the U.S. Export-Import Bank and would not label China as a currency manipulator.

"When you have that type of shift, the question becomes ... how much more 180 degree turns are we going to have?" said Gene Tannuzzo, senior portfolio manager at Columbia Threadneedle.

Some analysts have long been skeptical that the U.S. economy can accelerate significantly regardless of policy, as it continues to face headwinds including an aging population and low productivity growth.

The **GDPNow model from** the **Federal Reserve Bank of Atlanta currently suggests the U.S. economy grew at a 0.6% rate in the first quarter**.

That is **hardly the big lift in growth that investors anticipated** after Mr. Trump's victory. Still, other economic models are more optimistic and many investors aren't too concerned about economy over all. Even if growth has been modest, the labor market has been steadily tightening, leading to slowly rising wages that have contributed to firming inflation figures.

Some investors and analysts believe that yields are bound to recover now the market, after months of discounting risks to the economic outlook, is gripped by concerns about global conflict and much more skeptical about the potential for any positive developments.

"I'm inclined to think that we're in a temporary blip," said Thomas Simons, senior vice president and money-market economist in the fixed income group at Jefferies LLC. As the Fed's June policy meeting approaches, officials will likely try to prepare the market for another rate increase, causing yields to rise, Mr. Simons said.

Matt Added the Data Below — Source WSJ:

2016-2017 Fixed Income Trends

WSJ	6-Feb-16	5-Apr-16	5-May-16	1-Jul-16	1-Sep-16	25-Oct-16	28-Nov-16	29-Dec-16	31-Jan-17	13-Apr-17
UST Yields	**Yield (%) At Close**	**Yield (%) Noon EST**	**Yield (%) At Close**	**Yield (%) Noon EST**	**Yield (%) Noon EST**	**Yield (%) Noon EST**	**Yield (%) 10 AM EST**	**Yield (%) At 1 PM**	**Yield (%) At 1 PM**	**Yield (%) 2:57 PM**
1-Year Note	0.516	0.568	0.517	0.458	0.591	0.653	0.784	0.823	0.766	1.021
2-Year Note	0.670	0.728	0.722	0.597	0.790	0.865	1.119	1.218	1.208	1.206
3-Year Note	0.830	0.846	0.859	0.698	0.898	1.000	1.381	1.475	1.467	1.415
5-Year Note	1.161	1.180	1.200	0.998	1.175	1.276	1.814	1.952	1.918	1.771
7-Year Note	1.486	1.498	1.515	1.259	1.437	1.547	2.141	2.262	2.261	2.045
10-Year Note	**1.749**	**1.729**	**1.744**	**1.443**	**1.570**	**1.757**	**2.327**	**2.464**	**2.463**	**2.236**
30-Year Bond	**2.577**	**2.551**	**2.600**	**2.224**	**2.234**	**2.500**	**2.989**	**3.073**	**3.069**	**2.892**

Q4 2015 Federal Funds Rate Target lifted by **25 bps** to 0.25 to 0.50
Q4 2016 Federal Funds Rate Target lifted by **25 bps** to 0.50 to 0.75
Q1 2017 Federal Funds Rate Target lifted by **25 bps** to 0.75 to 1.00

Consumer Interest Rates Source: WSJ

Date	11-Mar-16	13-Apr-16	2-May-16	8-Jun-16	1-Sep-16	25-Oct-16	28-Nov-16	29-Dec-16	31-Jan-17	**13-Apr-17**
15-Yr Mortgage	2.92%	2.81%	2.87%	2.83%	2.79%	2.82%	3.31%	3.50%	3.36%	3.23%
30-Yr Mortgage	3.70%	3.56%	3.64%	3.58%	3.51%	3.55%	4.14%	4.29%	4.16%	4.01%
New Car Loan 48 Mo.	3.17%	3.18%	3.21%	3.16%	3.14%	2.93%	3.02%	3.00%	3.13%	3.23%

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FASB Proposes Changes to Several Aspects of Pension Accounting

by: Jay Seliber, Partner andNicole Berman, Director
PricewaterhouseCoopers (PwC) — In Brief:
http://www.pwc.com/us/en/cfodirect/publications/in-brief/fasb-pension-accounting-benefit-plans.html

January 26, 2016, FASB issued two proposed Accounting Standards Updates (ASU):

1. Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, and
2. Changes to the Disclosure Requirements for Defined Benefit Plans

Proposed changes to the presentation of benefit costs:

Under current US GAAP, the net benefit cost[1] for retirement plans comprises several different components (such as **service cost**, **interest cost**, **expected return on assets**, and the **amortization of various deferred items**), but is required to be treated and **reported as an aggregate amount of compensation cost**. While not changing any of the recognition and measurement provisions of current retirement benefits accounting, the FASB is proposing changes to the presentation of the net benefit cost in an effort to improve the transparency and usefulness of financial information.

Under the FASB proposal, sponsors of benefit plans would be required to:

1. Present service cost in the same line item or items as other current employee compensation costs, and present the remaining components of net benefit cost in one or more separate line items outside of income from operations (if that subtotal is presented); and
2. **Limit the components of net benefit cost eligible to be capitalized** (for example, as a cost of inventory or self-constructed assets) to service cost.

These amendments would be applied retrospectively for the presentation of service cost and other components of net benefit costs, and prospectively for the capitalization of service cost.

Proposed changes to benefit plan disclosures

The proposed ASU is the result of the FASB's application of its proposed amendments to the conceptual framework as part of its separate disclosure framework project. The proposed changes are intended to align benefit plan disclosures with the FASB's broad disclosure objectives. The objective of the benefit disclosures would be more clearly articulated under the proposed ASU. The changes also clarify that **materiality** should be considered when assessing the disclosure requirements and emphasize that **entities can use appropriate discretion**.

Consistent with the revised objective, the proposed ASU removes certain disclosures that are not considered useful or are out-of-date. For example, as proposed, disclosure of the amount of the accumulated benefit obligation for pension plans, information related to the June 2001 amendments to the Japanese Welfare Pension Insurance Law, and the amounts in accumulated other comprehensive income expected to be recognized as components of net benefit cost over the next fiscal year would no longer be required.

The FASB has also proposed adding several new disclosures, such as a description of the nature of the benefits provided, the employee groups covered, the type of benefit plan formula used, the weighted-average interest crediting rate for cash balance plans, and quantitative and qualitative disclosures about assets measured at net asset value based on the practical expedient in ASC 820, Fair Value Measurement.

These amendments would be applied retrospectively to all periods presented, except the qualitative disclosures about plan assets measured at **net asset value**, which would only be required beginning with the period of adoption.

The effective date and whether early adoption will be permitted for both of these proposed standards will be determined after stakeholder feedback is considered.

Why is this important?

As proposed, the financial statement presentation changes will affect all companies with pension or other postretirement benefit plans. The **most significant impact will be on companies that capitalize pension cost into inventory or other self-constructed assets**. The **amount capitalized will likely be lower since it will only include service cost**, which will impact margins. Furthermore, companies that report income from operations could see significant changes as a result of only including service cost in that category. The change in presentation could also influence entities that may have been considering making other changes to net benefit cost accounting, such as adopting immediate recognition of gains and losses or changing the manner in which interest cost is calculated.

While the disclosure changes will impact all entities with pension or other postretirement benefit plans, the FASB does not anticipate that entities will incur significant cost related to the changes.

What's next?

Comments on both of the proposed Accounting Standards Updates are due by April 25, 2016.

Questions?

PwC clients who have questions about this *In brief* should contact their engagement partner. Engagement teams who have questions should contact the Revenue, Liabilities, and Other team in the National Professional Services Group (1-973-236-7802).

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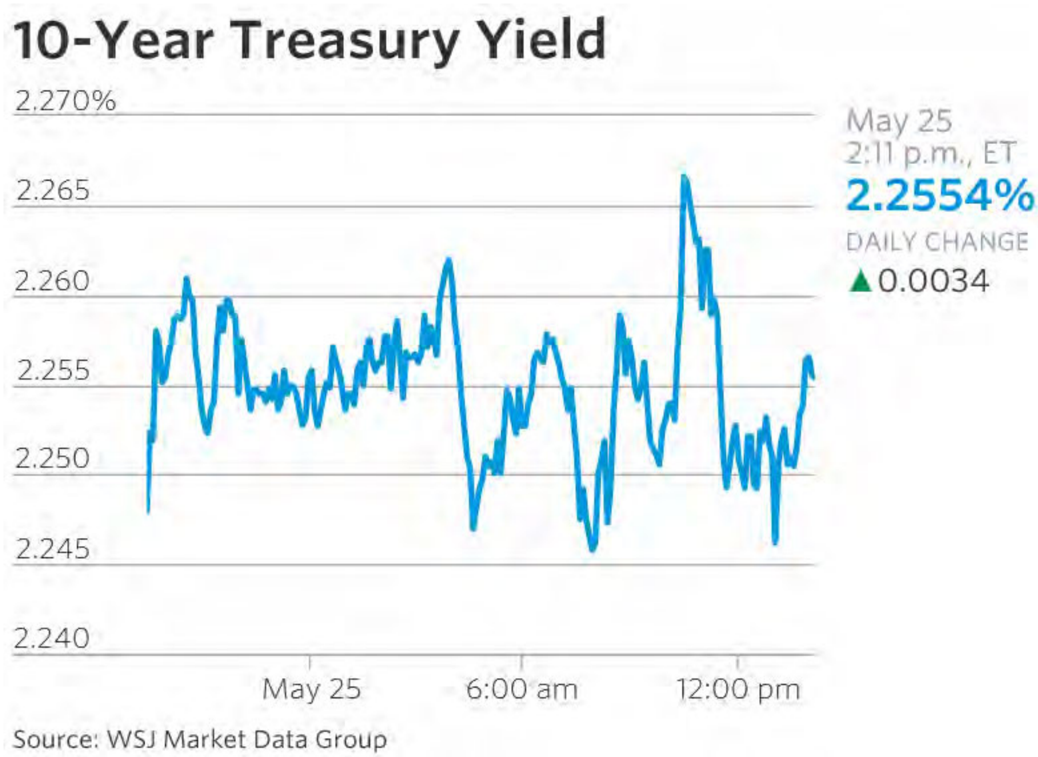
U.S. Government Bonds Stronger on Fed Signals

by Min Zeng – WSJ – May 25, 2017

Investors cheer signs Fed tightening to proceed in a slow manner



The U.S. government bond market strengthened Thursday for a second consecutive session, as investors continued to cheer on the Federal Reserve's signals that its tightening campaign would continue to proceed in a slow manner to avoid rattling markets.

In recent trading, the yield on the benchmark 10-year Treasury note was 2.250%, according to Tradeweb, compared with 2.266% Wednesday. Yields fall as bond prices rise.

The Bank of America Merrill Lynch MOVE index, which measures implied Treasury bond price swings based on options, pointed to subdued expectation over price swings. The index settled at 54.4058 Wednesday, the lowest level since Aug 2014, another sign the **Fed minutes** released Wednesday afternoon **reduced fears over** a **big rise in yields**.

A lower reading suggests **investors expect** smaller price swings or a **relatively tight trading band for yields**.

The bond market faces $28 billion sale of seven-year notes at 1 p.m. Thursday, the last leg of this week's new Treasury debt offerings. This factor contained the declines in bond yields. Some bond traders expect decent demand, given that the two-year and five-year note sales earlier this week drew solid buying.

The Fed's minutes for its May 2-3 policy meeting suggest the **central bank** is **on track** to **raise short-term interest rates next month**. **But** officials signaled they **may hold steady** if economic conditions don't warrant a move so soon.

In addition, **Fed officials suggested** a **slow and predictable** manner when they start the **process** of **winding down** its **large balance sheet** which includes more than $2 trillion worth of Treasury bond holdings.

Traders and money managers say the release reassures investors that the central bank would try to **avoid** a repeat of the "**taper tantrum**". U.S. Treasury bond yields soared in 2013 as fears that the Fed would soon dial back bond buying spook sentiment. Higher yields rippled broadly into corporate debt and emerging markets, causing a record pace of outflows from bond funds, tightening financial conditions and undercutting the U.S. growth momentum.

"The risk of another taper tantrum is fairly low,'' said John Bellows, portfolio manager at Western Asset Management Co. "The Fed doesn't want to disrupt the economic recovery. The Fed doesn't want to disrupt markets."

The **10-year Treasury yield has fallen this year after a big rise in late 2016**. The yield traded at 2.446% at the end of 2016. In mid-March, it had traded above 2.6%.

Left: Fed Chair Yellen – Investors continued to cheer on the Federal Reserve's signals that its tightening campaign would continue to proceed in a slow manner.

Lower Treasury yields are encouraging some investors to dial up risk spectrum in a bid to get more income. The S&P 500 index reached a fresh record high Thursday, deepening its rally this year.

Lower bond yields also reflect a camp of thoughts in the bond market that after a possible hike in June, the Fed may stand pat for the rest of the year, say some analysts.

This explained why the bond market didn't sell off even as financial derivatives linked to bets on the Fed's policy outlook priced in a large probability that the Fed would pull the trigger at its June 13-14 meeting.

The idea runs against the Fed's projections in March about two additional hikes following the March move. Yet some investors say the Fed may be forced to pause given the uncertainty surrounding the outlook for the U.S. growth momentum, inflation and fiscal stimulus.

"Although the committee may want to raise rates again, **we feel the Fed will tighten in June and then shift its focus to the reduction of its balance sheet**," said **Sean Simko, head of fixed-income portfolio management at SEI Investments**.

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Hard Line on Immigration Threatens Growth

by Greg Ep — Capital Account — WSJ — Feb. 22, 2017

President Donald Trump hopes to deliver growth above 3% in the coming decade, which would be hard in the best of times. He and some of his fellow Republicans seem intent on making it even harder by putting the brakes on immigration.

It is a **basic** rule of **economics** that a **nation's output depends on the number of people it employs and how productively they work**. The **Federal Reserve**, the **Congressional Budget Office** and **most private economists think output will grow a mere 2% per year in the next decade**. To beat the consensus, Mr. Trump and Republicans need to find ways to get the labor force or productivity to grow much more quickly.

That could mean getting millions of Americans who have quit the labor force to return. But it's a tall order because the **population is aging**. **That leaves immigration**. Yet Mr. Trump campaigned on limiting legal and illegal immigrants, citing the need to protect jobs and public safety. His administration has already expanded deportation of illegal immigrants. Two weeks ago Tom Cotton and David Perdue, Republican senators for Arkansas and Georgia, respectively, introduced a bill that would cut annual legal immigration in half, to 539,958 by the 10th year.

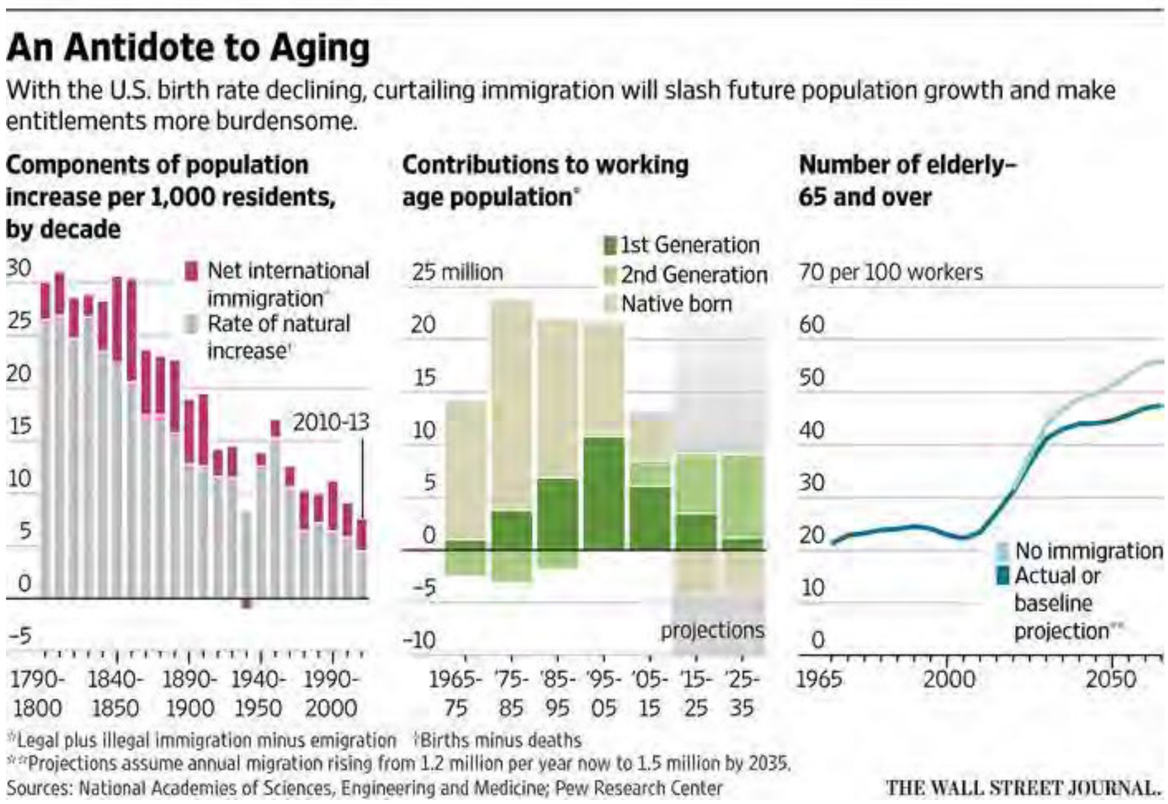
Current legal and illegal immigration, **net** of emigrants (those who leave), is now **around 1 million per year**, or **just 0.3% of the existing population**, below the 0.4% average since 1790, according to an exhaustive study last year by the National Academies of Sciences, Engineering and Medicine.

That relatively modest number looms especially large in the future of the U.S. for one simple reason. Because of **falling fertility rates**, the **natural rate of U.S. population growth** (**births minus deaths**) has **fallen to 0.4%**, its **lowest since** the **founding of the republic**. On current trends, it will only get closer to zero, which **means immigration will account for all the growth in the labor force**.

Immigration's economic significance is greater than even these numbers indicate for two reasons. **First, immigrants** are usually **younger** than the native born population: about 65% are working age, between 25 and 64, compared with 52% of the native-born. Also, among immigrants just 5% are over 65, compared with 15% of the native born. **Second**, **immigrants will have children who will bolster the labor force in later decades**. The contribution from the children of native-born parents "will simply be outnumbered by the flood of departing baby Boomers," the NASEM study says.

Consider this: The working-age population grew on average 1.4% per year from 1965 through 2015, when economic growth averaged 3%. The Pew Research Center estimates that at current immigration rates, the working-age population will grow just 0.3% per year in the coming two decades. With half a million fewer immigrants per year it grows just 0.1%, and with 1 million fewer, the working-age population shrink by 0.1% per year.

By contrast, when immigration was last curtailed in the 1920s and 1930s, the long-term consequences were masked by the baby boom, which began around the time the missing immigrants' children would have entered the labor force. Ending immigration now wouldn't turn the U.S. into Japan, whose fertility rate is far lower, but it would put the U.S. in a situation it has never seen before: near-zero population growth.



Does it matter if the U.S. population stops growing? In theory, an American isn't richer or more productive just because the population is larger. Reduced immigration is mostly a loss for the would-be immigrants, not the host country. Reality is different because immigrants differ in two crucial ways from the native born. First, **because they're younger, they shoulder some of the cost of pensions and health benefits for the soaring retiree population**, which are adding to budget deficits. According to Pew, the **number of retirees per 100 workers will climb from 27 now to 48 by 2065 on current trends**. This **ratio hits 56 with no immigration**.

Second, they **tend to bring skills that are in great demand**. A recent National Bureau of Economic Research study by John Bound, Gaurav Khanna, and Nicolas Morales found that the influx of tech workers using the H-1B visa, a permit for skilled workers, during the late 1990s depressed the wages of U.S. computer workers and scientists by 3% to 10% but made the overall country better off by boosting innovation and reducing prices for consumers.

Mr. Trump's anti-immigration stance clearly struck a chord with millions of voters worried that rising ranks of foreign-born, in particular the undocumented, threatened their jobs, the character of their communities, the nation's borders and national security. Nor is the existing system economically optimal: It prioritizes family reunification over highly educated professionals. Yet if Mr. Trump is to deliver the growth he promised, he will have to reconcile those anxieties with the demographic vise of an aging society.

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Insatiable Demand for Long Bonds Isn't Short Term

by Jon Sindreu — WSJ — Mar. 30, 2017

Christopher Whittall contributed to this article.

Bonds maturing in 30 years, 50 or even later, will likely continue to see strong demand. Even as interest rates rise, hunger for long-term government debt won't fall — keeping yields low.

The U.S. Treasury Department building in Washington, DC.

Even as interest rates rise, bond buyers' **needs for long-term debt are growing, meaning yields are likely to stay low**.

Regulations aimed at making the financial system safer mean that banks, life insurers and pension funds need sovereign bonds to meet liquidity requirements and match liabilities. This **month, more rules came into effect in** the **U.S. and Europe that could make that demand even stronger**.

Bonds maturing in 30 years, 50 or even later, will likely continue to see the sort of demand that last year helped push their yields to record lows.

Some investors had predicted these bonds would sell off amid increased expectations that central banks will raise interest rates and start tapering their massive bond-buying programs.

'Demand for longer-dated higher-yielding cash flows is very, very present.'

— Scott Thiel, portfolio manager at BlackRock

But the continued demand from investors and banks due to the regulatory changes could keep long-term yields much lower than they were before the 2008 financial crisis, others say. That is even as healthier economies push central banks to tighten monetary policy.

"**Demand** for **longer-dated higher-yielding cash flows** is **very, very present**," said **Scott Thiel**, **portfolio manager at BlackRock** Inc., the **world's largest investor** with more than **$5 trillion under management**. "It gets at the heart of why I don't think the selloff will be disorderly."

Last October, bond markets came under pressure amid signs of stronger global growth and inflation. Since the turn of the year, though, bonds have traded sideways even as stocks have risen.

Yields on long-dated debt are still near their historic lows. **Yields on 30-year Treasurys are now at 3%** compared with 2.3% in October. Surprisingly, debt of even longer maturities has reacted less. In the U.**K., 50-year bonds** yield 1.6%, surprisingly below the 1.8% returns offered by 30-year debt.

The Federal Reserve has nudged up rates twice since December to offset expectations of higher inflation. From next month, the European Central Bank will slow down the pace of its monthly bond purchases to €60 billion ($64 billion) from €80 billion.

Some analysts say that the continued low yields on long-dated bonds are a sign that investors expect less stellar economic growth over the long term.

Other analysts have a simpler take: these bonds are simply **in demand**, **making** the **term premium shrink**.

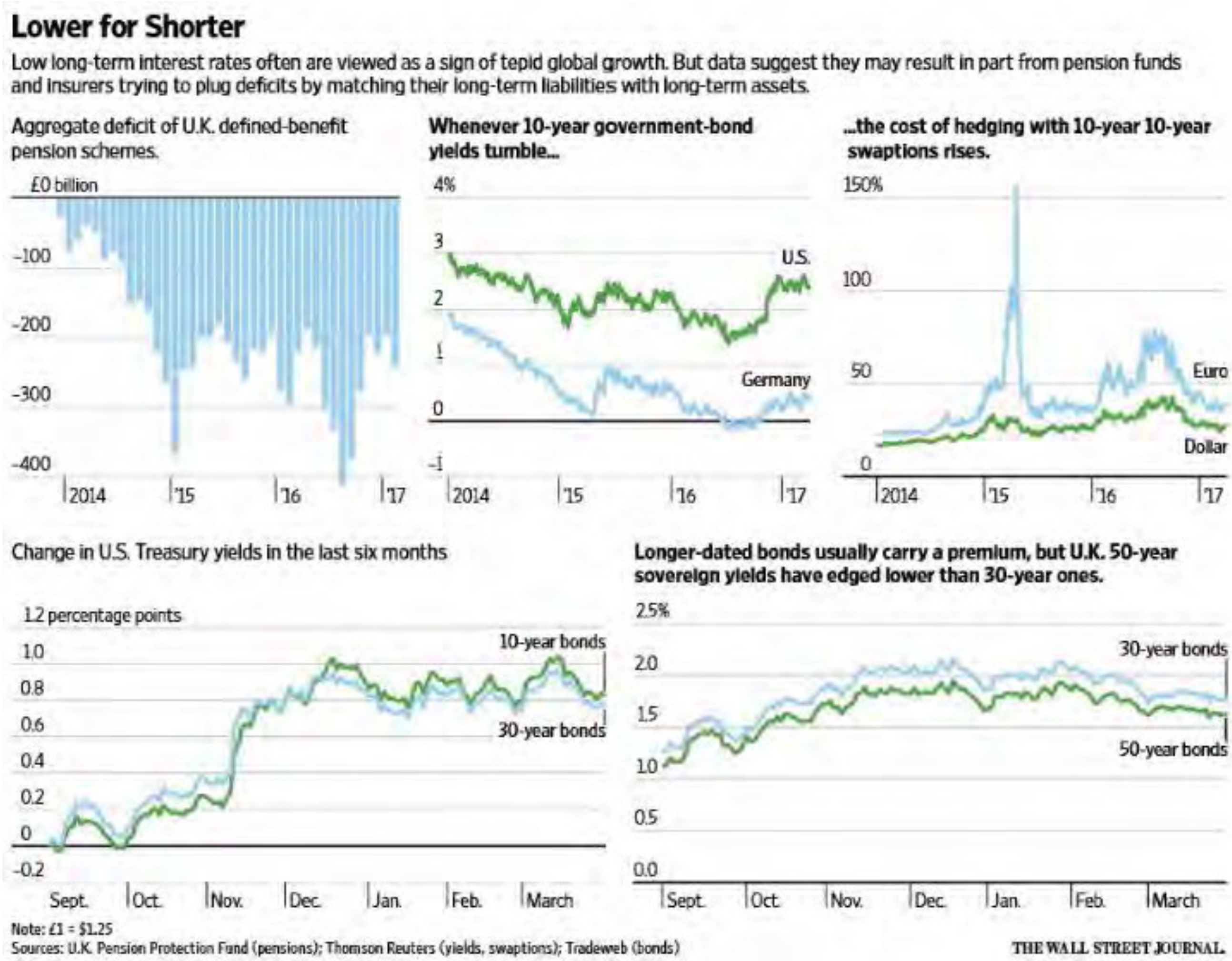
"Far from being a window on the future that reveals insights that no individual market participant has, low yields may, instead, reflect very ordinary motives of individual investors," said Hyun Song Shin, head of research at the Bank for International Settlements in a speech this month.

These motives are often **structural**.

Banks' appetite for sovereign debt has increased because, **to meet new post-crisis liquidity requirements**, they need assets that are easy and quick to sell during times of distress. **Government bonds** also **carry very little risk, so banks aren't required to raise much extra capital to hold them**.

Pension funds and insurers are buying more long-dated bonds as hedges instead, which has created a massive demand for long-term bonds that has **kept their yields low even as interest rates rise**.

Bonds are also a crucial — and increasingly scarce — source of **collateral for investors that borrow in short-term markets**.



Another major source of demand comes from **insurers and pension funds**, especially **in Europe**.

Euro-zone insurers, **most of them German**, hold more than €7 trillion ($7.6 trillion) worth of assets, while pension funds account for another €2.4 trillion. **Promises** from these investors **to pay beneficiaries and policyholders span far into the future**. Whenever rates plummet, the value of these liabilities surges at an accelerated rate compared with their assets and, to square their books, they **have to buy assets with long maturities**.

As yields fell **between 2013 and 2016**, **German insurers extended by roughly 25% their holdings of bonds maturing in 20 or more years**, while shedding some of their shorter-term bonds.

Insurers and pension funds also use derivatives such as interest-rate swaps, to hedge their exposure to the **risk of rates going lower**.

Derivatives have become more expensive to use after post-crisis rules constrained banks' trading in these markets. Rules have also pushed transactions to be centrally cleared. European pension funds have so far been exempt, but that is set to change. Also, from this month, regulators will demand more collateral to do such transactions.

All this has **increased the reliance on extra-long bonds**.

"**Ten years ago it was almost all swaps and very few bonds**, but the way we have arranged our portfolio **over the next 10 years** is **more bonds and less swaps**," said Kasper Arndt Lorenzen, chief investor at Danish pension provider ATP. "**Derivatives are just more complex and more costly**."

J.P. Morgan Chase & Co's London **derivatives structuring desk** said that **instead of using swaps**, **some** of their **clients** were **now flocking into 40-year and 50-year issues of debt**.

As demand has increased, supply has followed. **Last year European governments locked in ultra-low borrowing costs by issuing debt at ever longer maturities**. **Ireland and Belgium even sold 100-year paper**.

Even so, **there isn't enough to satisfy ever growing demand**, investors say. **Pension funds** are even buying into real estate and infrastructure, which are also long-term investments, at the cost of keeping a less-liquid portfolio.

"The **bond market isn't deep enough for us**," said Paul Van de Moosdijk, senior treasurer at Dutch pension fund PGGM. "**Liquidity risk from pension funds is significantly rising**."

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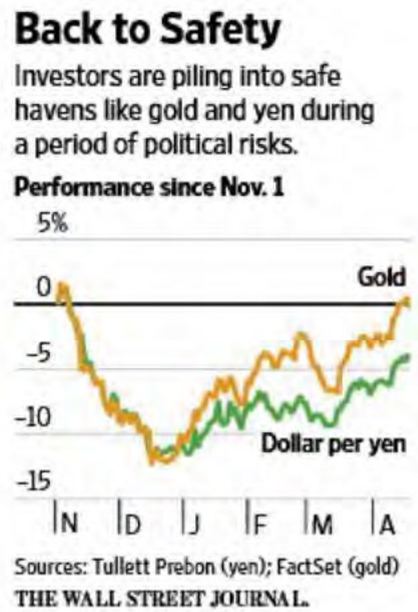
Investors Flip Switch to Risk-Off Mode

by Ira Iosebashvili — WSJ — Apr. 20, 2017
Timothy Puko and Gunjan Banerji contributed to this article.

Investors are bidding up prices for gold, Japanese yen and other **haven assets,** seeking cover from political and economic risks that are spreading across the globe.

Gold prices rose to their highest level since November this week and are up 11% this year. The yen reached a five-month high against the dollar on Monday. Other **assets that tend to rise during times of turmoil**, such as Treasurys, have **gained steadily this month.**



Riskier investments such as emerging markets have turned volatile recently, and the Dow Jones Industrial Average was off to its worst month since January 2016 before rebounding on Thursday.

The blue-chip index rose 0.9%, while gold and other haven assets were flat or weaker on the day after some solid earnings reports. But traders said the mood in the market remained shaky, despite a relief rally.

Driving the shift to safety is a series of **geopolitical events** that are beginning to rattle investors. **Some** of these political concerns, **like** heightened **tensions over North Korea's nuclear-weapons program** have been **around for years but intensified in recent days**.

IHS Markit, a risk-consulting firm, warned in a Tuesday note about North Korea that "the risk of escalation and miscalculation following weapons tests, military exercises, or isolated attacks is greater now than at any point in the past 10 years." **U.S. airstrikes in Syria and Afghanistan** also have rekindled fears about those conflicts spiraling out of control.

Other concerns have appeared out of nowhere, like the sudden rise of French far-left presidential candidate Jean-Luc Mélenchon. With **France** going to the polls on **Sunday**, investors worry that **candidates from two political extremes** could face each other in a runoff.

Either one would be a bad outcome for stability and markets, investors say.

"**Typically**, you get a market environment that is consumed by a **single issue**," said Robert Tipp, chief investment strategist at PGIM Fixed Income. "**Now**, the attention is focused all across the globe, on a **number of issues**." Mr. Tipp increased positions in longer-dated Treasurys in the first quarter, in part to mitigate risk from political events.

The **flight to safety** is also a **sign that investors are losing confidence** that President Donald Trump can deliver a **new** fiscal **policy to stimulate** the **U.S. economy** after Republican efforts to overhaul health care collapsed amid other roadblocks, though Treasury Secretary Steven Mnuchin said on Thursday that the administration expected to release a tax plan "very soon."

The belief that Mr. Trump and a GOP-controlled Congress could enact tax cuts, deregulation and other business-friendly policies drove stocks higher after the election, but many investors have been reversing those trades in recent weeks. The **latest U.S.**

inflation and jobs data also disappointed, **raising new concerns** that the **U.S. economy may be hitting a soft patch.**

Rising doubts about growth are also weighing on the dollar. The U.S. currency shot higher in the weeks after the election, but is down 3.4% against a basket of other currencies this year. With **traders** uncertain whether the multiyear dollar rally can restart, they are **putting money in assets perceived as safer** as they reassess.

Riskier investments such as emerging markets have turned volatile recently, while the S& P 500 is off 1.7% from a 52-week high hit in March.

The CBOE Volatility Index, or VIX, has also climbed around 14% this month to 14.15 and is well above its average in the first quarter, when it hovered at historic lows. Dubbed the “fear gauge,” the index is based on options prices on the S& P 500 index and tends to rise when stocks decline.

In addition to political unrest, some investors are worried about signs of a **slowdown in China’s economy**. That is **starting to weigh on commodities**. Iron-ore prices are down about 18% this month, due in part to weaker housing data in China, analysts say. China is the world’s largest consumer of raw materials.

Deltec International Group, a private banking and wealth management firm in the Bahamas, is cutting back on its bullish bets, anticipating a more volatile second quarter. The firm is paring back on U.S. stocks and is adding to its bond-holdings, said Atul Lele, Deltec’s chief investment officer. “The **biggest risk to markets is**…that **growth momentum is slowing**,” Mr. Lele said. “And it means risk assets are going to decline

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Markets Send a Worrying Message about the Economy

by James Mackintosh — WSJ — Apr. 20, 2017

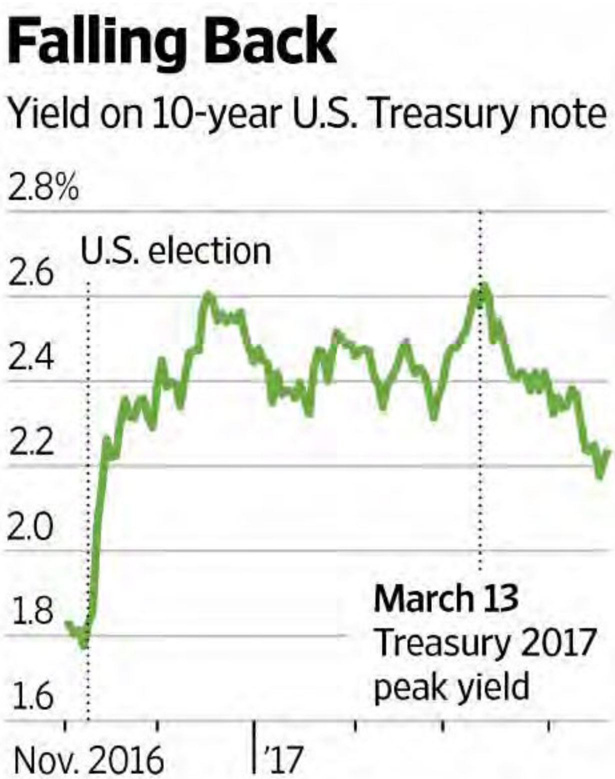
With hopes dashed that business-friendly reforms will get quick implementation in the U.S., investors are reverting to wagers on anemic growth

Markets are flashing red on growth as investors begin to return to pre-election bets on the “new normal” — a **persistently weak economic expansion**.

The shift back is far from complete. And the assessment is muddied by geopolitics and the uncertain French election.

But there are signs that the sugar rush of Donald Trump’s victory and global-growth hopes has faded, raising doubts among some investors about whether stocks can stay high.

The **sharp drop in government-bond yields is the most obvious signal that something is amiss**. It is backed up by **ominous signs from raw-materials markets, where copper and iron-ore prices have tumbled**, and a **swing in** leadership of the **stock market** away from go-go bank shares and cheap "value" stocks **to safety-first utilities**, real estate and companies with high-quality balance sheets and reliable earnings. All this has come as **inflation expectations priced into bonds have fallen** and as **some weak data has led to downgrades of economic forecasts**.



Note: Yields fall as bond prices rise.
Source: Tullett Prebon
THE WALL STREET JOURNAL.

Technology stocks' return to favor also suggests investors are looking for companies able to deliver growth even if the economy is weak.

"The new normal's still with us," says **Scott Minerd**, **chief investment officer of Guggenheim Partners**. Investors, at least for a time, thought the promise of change that came with Mr. Trump's election could help break the U.S. economy out of slow-growth mode, Mr. Minerd said. "So far, we're **long on promise and short on delivery**. The **market's waking up to that**."

There are two big question marks around the market portents: Are they right? If so, do they spell doom for shares?

One way the omens could be wrong is if they are caused by something other than a slowdown. The most obvious candidate is **geopolitics**, with **money seeking safe havens** ahead of Sunday's **French election** and amid the concern about **North Korea's nuclear threats**. It is impossible to know how much this has **depressed bond yields**, but **buying of bond-like utility** and real-estate **stocks** might be a result of falling bond yields, rather than supporting evidence of a slowdown. Commodity prices need a separate explanation, but their fall might just be coincidence.

The market message could also be wrong if the economy is just fine. Evidence is gathering that the hoped-for rebound didn't come through in the first quarter, with the **Federal Reserve Bank of Atlanta's** "nowcast" **of first-quarter growth down to just 0.5%, from above 3% in early February**. Economic surprises — the degree to which reported data beat forecasts — are now barely positive, too, having dropped back from a three-year high in March, according to Citigroup.

But there is a long history of first-quarter data being wrong due to seasonal adjustment errors, and the "soft" survey data is still strong, if less so than it was.

The White House and Congress have failed so far to make progress on tax cuts or **infrastructure spending**, either of which **could give the economy a boost**. But Mr. Trump is nothing if not flexible, and a deal later this year is plausible.

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New President, Same Old Economy

by Justin Lahart — WSJ — Apr. 3, 2017

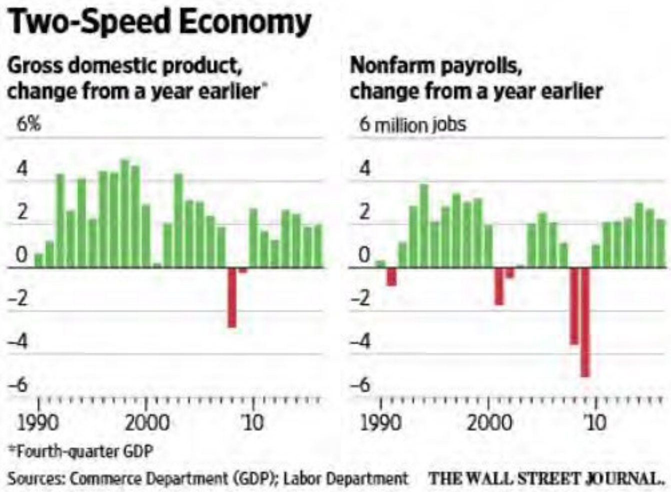
With the chances of a big tax-cut and spending package looking slimmer, the economy under President Trump could stay stuck in its low-growth rut.

When it comes to the U.S. economy, investors might be best off expecting more of the same, only less so.

Until recently, it appeared that President Donald Trump was destined to engineer a boost. Even if he wasn't able to entirely deliver on his campaign pledges, with Republicans controlling Congress a meaningful tax-cut and infrastructure-spending package seemed like a gimme. That should have been good enough for at least a temporary bump and many envisioned a lasting lift to the economy's growth trajectory.

After the failure of the health-care bill, and the rifts it exposed among Republicans, the chances of meaningful tax reform — much less an infrastructure bonanza — are looking lower. An easy-to-pass, low-bore tax cut that doesn't do much to move the needle on the economy, but that can at least give Mr. Trump and congressional Republicans something for the win column, looks more likely.

How meaningful might that be? A **good exercise in what to expect is to consider what things might look like without a tax-cut and spending boost with a further assumption that any salutary effects that reduced regulation have on growth are balanced by the drag from Mr. Trump's tough stances on immigration and trade**. What is left is an economy that, despite some lofty stock valuations, isn't exhibiting a lot excesses that precede recessions. Conversely, the economy also probably wouldn't escape its slow-growth rut.



For example, forecasting firm **Macroeconomic Advisers** — **which hasn't incorporated any tax-cut or fiscal stimulus estimates into its estimates** — reckons that **gross domestic product** in the **fourth quarter of 2017** will be **2.3% above** its **year-earlier level**. That would count as an **improvement from** the **2%** registered in 2016 and reflects an expectation that consumer spending will stay steady while housing activity and capital spending pick up.

That is **better but not all that different from the 2.1% growth GDP has averaged over the past three years**. What is more, the **firm forecasts growth will cool again in 2018**.

The risk is that, as the job market tightens, the economy won't even be able to sustain its recent pace for very long. Consider that, despite mediocre growth, the economy has added an average of 225,000 jobs a month over the past three years. If that were to continue, it wouldn't take long for the job market to get very tight, prompting the Federal Reserve to pick up the pace on rate increases in an effort to prevent an overheating episode.

True, there might still be a little wiggle room on jobs. Even though the unemployment rate is at a low 4.7%, there are probably still some people who have been out of the labor force (and therefore aren't counted in the unemployment rate) who might still be enticed into the job hunt. And with some efficiency gains, the economy might not need quite as much job growth to meet growing demand.

But at this point those are things that count more as wishes than things upon which to base a forecast — sort of like tax-cuts and spending pledges.

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Portland General Electric Co. (POR) Moves Higher on Volume Spike

by Equities Staff — equities.com –- Feb. 23, 2017
https://www.equities.com/news/portland-general-electric-co-por-moves-higher-on-volume-spike-for-february-23 — views expressed are those of the authors.
All data provided by QuoteMedia was accurate as of 4:30 PM ET.

Portland General Electric Co is an electric utility company.

Last Price $ 44.65	**Last Trade** Feb/24 - 14:23
Change $ 0.47	**Change Percent** 1.06 %

Open $ 44.31

High $ 44.84

52 Week High $ 45.21

Market Cap 3,971,480,514

Volume 404,310

Prev Close $ 44.18

low $ 44.31

52 Week Low $ 37.04

PE Ratio 1.69

Exchange NYE

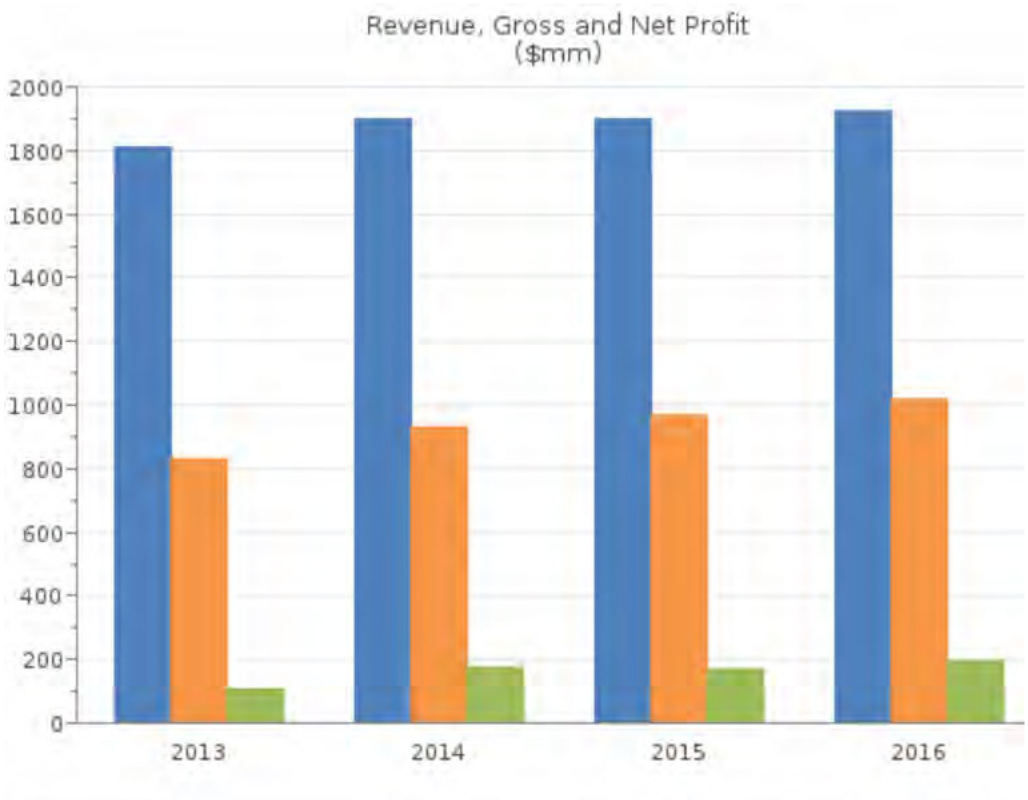
POR - Stock Valuation Report

Portland General Electric Co (POR) traded on unusually high volume on Feb. 23, as the stock gained 1.01% to close at $44.18. On the day, Portland General Electric Co saw 872,501 shares trade hands on 6,834 trades. Considering that the stock averages only a daily volume of 479,938 shares a day over the last month, this represents a pretty significant bump in volume over the norm.

Generally speaking, when a stock experiences a sudden spike in trading volume, it may be seen as a bullish signal for investors. An increase in volume means more market awareness for the company, potentially setting up a more meaningful move in stock price. The added volume also provides a level of support and stability for price advances.

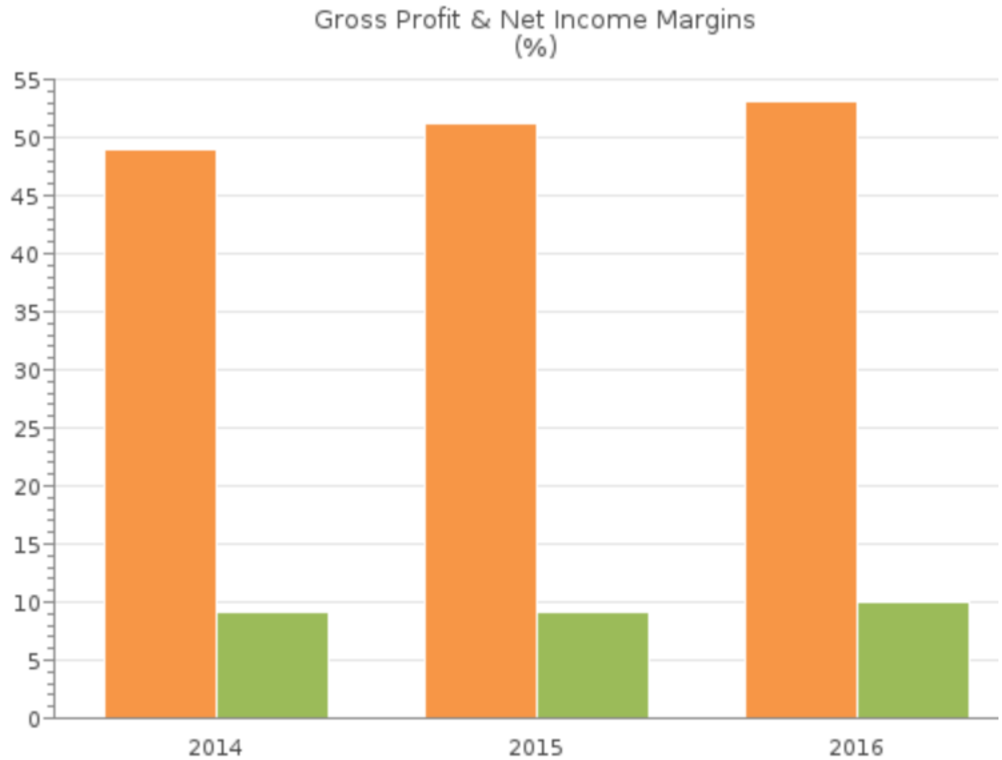
The stock has traded between $45.21 and $37.04 over the last 52-weeks, its 50-day SMA is now $43.36, and its 200-day SMA $42.23. Portland General Electric Co has a P/B ratio of 1.68. It also has a P/E ratio of 20.3.

Portland General Electric Co is a vertically integrated electric utility. The Company engages in the generation, purchase, transmission, distribution and retail sale of electricity in the state of Oregon.

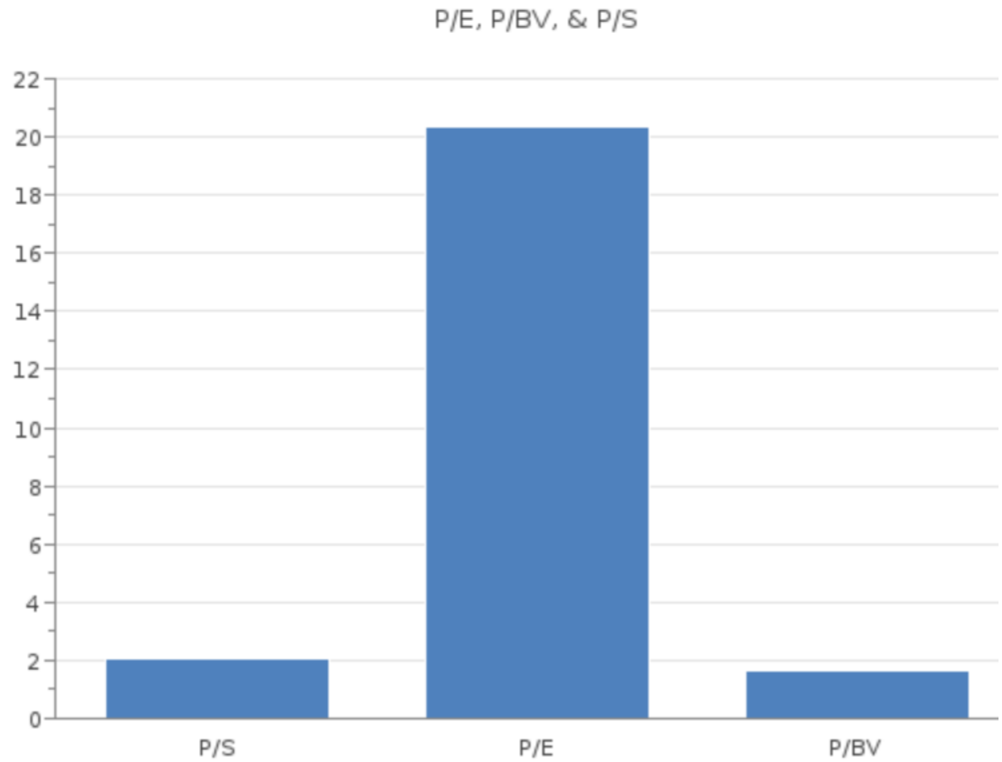


	2013	2014	2015	2016
Revenue	$1,810	$1,900	$1,898	$1,923
Gross Profit	$828	$930	$971	$1,020
Net Income	$105	$175	$172	$193

	2014	2015	2016
Revenue Growth Rate	4.97%	-0.11%	1.32%
Gross Profit Growth Rate	12.32%	4.41%	5.05%
Net Income Growth Rate	66.67%	-1.71%	12.21%



	2014	2015	2016
Gross Profit % of Sales	48.95%	51.16%	53.04%
Net Income % of Sales	9.21%	9.06%	10.04%



	P/S	P/E	P/BV
POR	2.04	20.36	1.68

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Portland General Electric Company
Downgrade to Neutral
PORing Cold Water on Our Expectations
UBS Securities, LLC – May 2, 2017:
Julien Dumoulin-Smith, CFA, Exec Dir – Equity Research
Jerimiah Booream, CFA, Assoc. Dir – Equity Research

Downgrading to Neutral: Risk reward more balanced ahead of 2H17 catalysts Following the 1Q17 update we are downgrading shares to Neutral as we see a less profitable path forward in POR's efforts to fill capacity needs. We are cutting our expectations stemming from the Integrated Resource Plan (IRP) and subsequent RFP process following more cautious commentary from mgmt. **Our probability weighted capex estimates for Carty 2 now stand at 50% vs prior 100%** as we believe that resource procurement could well include **PPAs or asset purchases**, rather than an outright build. This **likely diminishes the EPS upside** that could stem **from the Boardman plant replacement** (~400MW's), a key assumption in our model.

12-month rating	Neutral
	Prior: Buy
12m price target	US$45.00
	Prior: US$47.00
Price	US$45.03
RIC: POR.N BBG: POR US	

Trading data and key metrics	
52-wk range	US$46.38-39.83
Market cap.	US$4.00bn
Shares o/s	88.9m (ORD)
Free float	99%
Avg. daily volume ('000)	146
Avg. daily value (m)	US$6.5
Common s/h equity (12/17E)	US$2.43bn
P/BV (12/17E)	1.6x
Net debt / EBITDA (12/17E)	3.5x

EPS (UBS, diluted) (US$)

	12/17E			
	From	To	% ch	Cons.
Q1	0.85	0.82	-3	0.82
Q2E	0.44	0.40	-8	0.45
Q3E	0.30	0.27	-11	0.30
Q4E	0.70	0.79	14	0.65
12/17E	2.29	2.29	NM	2.27
12/18E	2.53	2.51	-1	2.46
12/19E	2.60	2.56	-2	2.56

Premium story already: Recent data points make us more cautious. We note shares have re-rated from a discount to a premium story over the last few years as mgmt. executed through a Carty 1 build and **posted solid EPS growth**. The path forward is less clear to us given execution woes through the 2016 IRP including a guide down on capacity needs, a challenging load forecast picture, as well as **decreased prospects of outright ownership of new generation assets**. We see the potential decision to pursue PPA's (expect announcement 2-4 months from now) as the next catalyst to move estimates lower. Overall, we see less risk to wind procurement given the RPS needs, though comments from mgmt. make it all the more clear an additional Unit at Carty could well be off the table. A PPA could always have been contemplated, though we emphasize **Street expectations are more aligned with a rate-base-able asset**.

Risk surrounds the 2018 GRC too: what will happen on tax elections? We look for the first comments out from Staff by June 16th which could re-open the prospects for **Bonus Depreciation**. With POR among the sole companies that has does not elect Bonus (nominally due to existing state tax deductions), we wouldn't doubt this remaining a contentious topic given our latest stakeholder discussions.

Valuation: PT **Lower to $45**: Lowering estimates and premium ascribed While we acknowledge the upside to shares does still exist, the path forward is less clear following the 1Q17 conference call. We are **lowering our ests due to lower capex forecasts**. We now ascribe a 0.5x premium valuation (vs 1.0x) to the 2019E peer set.

Highlights (US$m)	12/14	12/15	12/16	12/17E	12/18E	12/19E	12/20E	12/21E
Revenues	1,900	1,898	1,923	1,980	2,051	2,096	2,171	2,216
EBIT (UBS)	332	331	355	381	417	440	466	483
Net earnings (UBS)	176	172	193	204	227	238	253	265
EPS (UBS, diluted) (US$)	2.18	2.04	2.17	2.29	2.51	2.56	2.69	2.81
DPS (US$)	1.12	1.18	1.26	1.35	1.44	1.54	1.64	1.74
Net (debt) / cash	(2,374)	(2,206)	(2,344)	(2,504)	(2,644)	(2,765)	(2,723)	(2,659)
Profitability/valuation	**12/14**	**12/15**	**12/16**	**12/17E**	**12/18E**	**12/19E**	**12/20E**	**12/21E**
EBIT margin %	17.4	17.4	18.5	19.2	20.3	21.0	21.5	21.8
ROIC (EBIT) %	-	7.2	7.3	7.5	7.7	7.6	7.8	8.1
EV/EBITDA (core) x	8.2	8.9	9.3	9.2	8.6	8.2	7.8	8.0
P/E (UBS, diluted) x	15.3	17.8	19.0	19.7	17.9	17.6	16.7	16.0
Equity FCF (UBS) yield %	(20.4)	(4.0)	(1.9)	(1.2)	(3.9)	(1.4)	5.6	5.9
Net dividend yield %	3.3	3.2	3.1	3.0	3.2	3.4	3.6	3.9

Source: Company accounts, Thomson Reuters, UBS estimates. Metrics marked as (UBS) have had analyst adjustments applied. Valuations: based on an average share price that year, (E): based on a share price of US$45.03 on 01 May 2017 19:35 EDT

Pivotal Question: **Will the Integrated Resource Plan Lead to Additional Capex Awards?**

UBS View:

It is increasingly **uncertain** whether the opportunity to build and own rate-base qualified assets will come to fruition following a series data-points that decrease the prospects for Carty Unit 2. Mgmt most recently commented that the all options are on the table to source the ~500MW capacity need (down from ~850MWs), still pending acknowledgement from the Oregon PUC.

Evidence:

Mgmt noted on the recent 1Q17 conference call they are assessing bilateral opportunities, including Power Purchase Agreements to source the ~400MW resource needed to replace the Boardman facility. With this latest data-point clearly lowering the odds of an owned unit at Carty 2, we see the risk/reward in shares as more balanced.

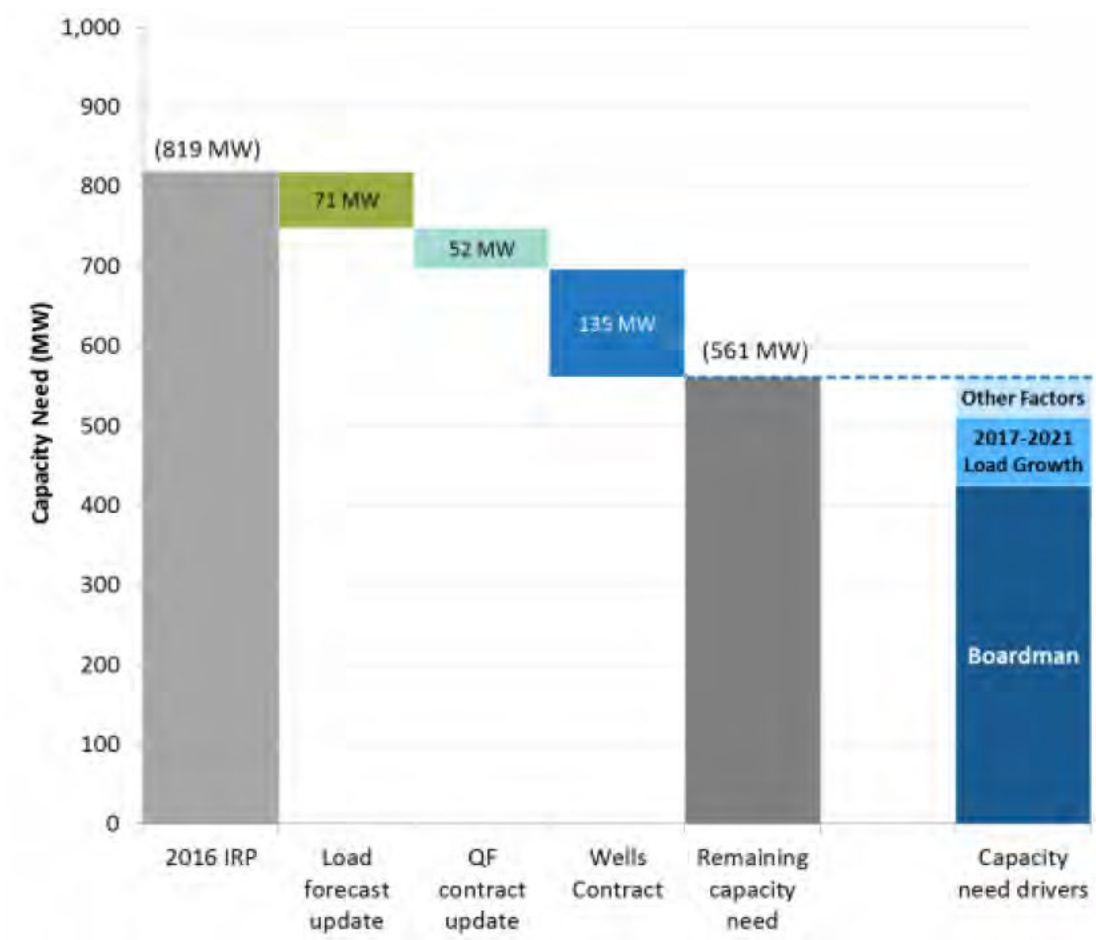
What's Priced In?

We believe the Street largely assumes an additional asset built to replace Boardman capacity (via **Carty Unit 2**) **as well as a wind procurement** to satisfy state RPS standards. **If mgmt. choses to service baseload capacity needs via PPA's we see estimates slipping further**.

POR IRP – Reply Comments Filed; Lower loads:

POR recently filed its reply comments for its 2016 IRP including an update to capacity needs from 819MWs to ~561MWs primarily driven by lower load forecasts, updates to QF contracts, and the re-contracting of the Wells Hydro facility (135MWs). We note the re-contracting was largely expected following our latest meeting with mgmt., though the lower capacity needs now standing at ~570MWs is largely made up of loss of Boardman (~400MWs) with the new updated load growth forecasts accounting for ~100MWs. Further comments on this past quarter's conference call decrease the likelihood for ownership opportunities for the Boardman capacity need. Based on the chart below, we believe 70-100MWs due to "other factors" could largely be explained by re-contracting opportunities. We further include a full list of contracts below.

Figure 6: POR: Capacity Need Impact due to Load and Contracts – Updated



Source: 2016 POR IRP Reply Comments

Capacity needs down, but load forecast unchanged:

We note the company continues to expect ~**1% LT load growth net of 1.5% impact of EE** though investors will largely question the latest update, due to the lower capacity needs delineated. We believe PORs assumptions in the front end of their load growth curve generally call for **flatter growth**, in line with the negative load demand experienced in 2016 and also expected throughout 2017 per the company's latest guidance. While this may cause skepticism, we emphasize the Boardman plant continues to drive the largest percentage of the capacity need. Further, generic wind could also be additive given the need to meet state RPS standards. Recent headlines by the **City of Portland** to move to **100% clean energy and renewables by 2035** only strengthens the argument here. We note POR would currently be at 50% if the City of Portland includes **hydro**, though there are still many **unknowns** with how City RPS could play out.

Portland Hydro Project: POR has a contract with the City of Portland to purchase the output from the Hydro projected located on the Bull Run River. The contract runs through 2017 and provides 10MWa.

North Wasco PUD: The agreement with Northern Wasco Country to purchase the entire output of the Dalles Fishway Northshore Project (5MW) will expire in September of 2017.

We include a full list of additional contracted capacity for multiple fuel types below, noting other contracts are set to roll off starting in Sept 2017. Near term expiries are presumably included in the resource needs noted above.

Figure 7: Summary of Additional Contracted Capacity

Contract	Contract Type	In Service	Expiry Date	MW	MWa
Baldock Solar	Renewable Purchase Agreement	Jan-12	Jan-37	1.5	0.2
Bellevue Solar	Renewable Purchase Agreement	Jul-11	Jan-36	1.4	0.2
Yamhill Solar	Renewable Purchase Agreement	Jul-11	Oct-36	1	0.1
Outback Solar	Renewable Purchase Agreement	Oct-12	Jan-37	5	1.2
Portland Public Schools (Solar)	Renewable Purchase Agreement	Oct-12	Sep-40	1.2	0.2
EWEB Stone Creek	Capacity Contract	NA	NA	0.6	
Iberdrola Summer Peak	Capacity Contract	Jul-14	Sep-18	100	
Iberdrola Winter Peak	Capacity Contract	Dec-14	Feb-19	100	
Shell Option	Option	Mar-14	Dec-17	300	
Covanta Marion	PPA	Jul-14	Sep-17	8	9.6

Source: POR IRP

IRP continues to be the front and center debate

Following our latest conversations with stakeholders, we emphasize willingness to accelerate **PTCs** to enable their use today despite lack of tax capacity; and assets built today would enable PTC generation for a decade, presumably largely through the period in which there is indeed tax capacity, and meaningfully improve the tax prospects today. While timeline for the IRP is a nascent concern, our focus remains on more the risks around demand in the thermal procurement rather than the renewable procurement given consternation on demand projections. We think the **risk** appears here principally **tied to timeline for replacement**, **as well as alternative resources**.

Figure 8: IRP Timeline

Date/Time	Event	Description
8/31/2017	Final Order due	Final Order due
7/28/2017	Staff Memo due	Staff Memo due
6/23/2017	PGE Final Comments due	PGE Final Comments due
5/12/2017	Staff and Intervenors Final Comments due	Staff and Intervenors Final Comments due
3/31/2017	PGE Reply Comments due	PGE Reply Comments due

Source: Oregon PUC

Where else is there Capex upside?

Cable undergrounding: Mgmt is looking to **replace 25 miles of cable on an annual basis noting there's 250 miles of cable needed to be replaced over the next 20 years**.

Substations: As it stands there are **69 substations deemed** "**higher risk**" with mgmts. next capex update in 3Q17, we look for further increases noting that 3Q16 included only 20 substations reviewed by the board and approved for **rebuilds**.

Pivotal Question: Is there risk to the LT EPS prospects?

UBS VIEW

Yes. We believe the incremental upside stemming from **capacity needs** could well be offset by the eventual inclusion of **Bonus Depreciation** as well as the risk of negligible load spilling over to the 2018 time period. We note this has already have had an effect on base EPS over the last two years.

Evidence

We Note $0.08 cents of impact on this Qtr due to **lower load growth**, equating to a 3.9% decrease, albeit this is lapping an extra day in Feb due to leap year. **While customer growth has increased 1.3% YoY in 2016, the Commercial sector remains key to reviving load metrics**. We note industrial customers and deliveries have ticked up of late, though this is lower margin business. Our recent stakeholder discussions have highlighted a **lack of tax capacity** and the decisions to not elect for **bonus depreciation** (an offset to rate-base) which could be among the most closely watched elements of the latest GRC.

What's Priced In?

We believe **buy-side expectations** are largely **pivoted towards the IRP, rather than the 2018 GRC where** we see **risk skewed towards** the **downside**. While the GRC itself represents risk in the form of picking back up the issue of electing bonus depreciation, we **could see the ROE revisited again**.

2018 GRC: What are the facts? 2018 GRC: awaiting Staff and Intervenor testimony:

We look forward to the first looks at Staff and Intervenor testimony expected by

June 16th. We note the previous 4 rate cases were settled with Staff with Settlement conferences scheduled for the beginning of August.
What's included? The filing including a forward '18 test year, an ROE of 9.75% and rate change request for ~$100Mn (5.6% increase for cost of service) with new rates being set in January 2018. **Base rate increases largely stem from reliability upgrades, including substation upgrades, cyber-security, emergency response and management**, as well as further **T&D system upgrades**. Mgmt noted in our meetings **intervenor push-back could come from the 5.6% rate increase,** as they typically have offsets in the past (Trojan decommissioning, Yucca Mtn), though this time around T&D investments are for some of their largest customers. Further, stakeholder discussions highlighted a **lack of tax capacity** and decision not to elect for **bonus depreciation**, which is among the most **closely watched elements in the latest 2017 rate case**.

Figure 9: POR 2018 GRC Timeline

Date	Event
April 7th	Deadline to file petitions to Intervene
May 5th	Staff Workshop
June 16th	Staff and Intervenors Open Testimony
July 18th	PGE Reply Testimony
Aug 3rd - 4th	Settlement Conferences
Aug 17th	Staff/Intervenor Rebuttal Testimony
Seot 5th	PGE Surrebuttal Testimony
Sept 12th	Parties file Joint Issues List
Oct 24th	Oral Arguments (Tenative)
Dec 21st	Taget Date for Commision Order
Jan 1st	New Rates Effective

Source: Co. Filing, OR PUC

Figure 10: Key 2018 GRC Metrics

Rate Case Summary OR: D-UE-319	Request
Rate Change Amount ($Mn)	99.90
Rate Change/ Revenue (%)	5.60
Rate Case Test Year End Date	12/31/2018
Rate Base ($Mn)	4,594.05
Return on Equity (%)	9.75
Common Equity to Total Capital (%)	50.00
Rate of Return (%)	7.46

Source: SNL

Load Growth

Mgmt continues to reiterate its expectations for **+1% long term annual load** growth noting the recent guide from 2016 (flat to down 1%) is not representative of the long term trend they're seeing. Mgmt. sees positive load growth trends driven by the **high tech sector**, noting customer count was up 1.2% over the past year. We see load growth remaining a contentious topic among investors with many pointing to the weather adjusted 2017 forecast in the prior two quarters having an impact. We look for further economic indicators across Oregon to support management's position, specifically on the industrial side and commercial side.

We note the **longer-term demographic trends are quite supportive**, with the long-term growth remains principally **driven by industrial trends** including primarily **tech**-related **companies**. Articulating a path back towards net +1% sales growth still remains unclear post the 1Q17. We wouldn't expect any meaningful reconciliation of these until after the pending rate case an RFP given how closely scrutinized demand profiles are in both processes; as such we see guidance next year with 4Q17 as the next real inflection on this point.

UPSIDE / DOWNSIDE SPECTRUM

Value drivers	P/E Multiple	Carty Unit 2 Capex Probability	Wind Capex Probability	Load Growth	2019 Avg Ratebase ($Mn)
$51 upside	20.1x	100%	100%	1.5%	5,897
$45 base	18.1x	50%	50%	1%	5,520
$40 downside	16.1x	0%	0%	0%	5,142

Source: UBS

Risk to the current share price is skewed (1.2:1) to the upside

Upside (US $51): Our upside scenario assumes 100% probability for $600M or more of incremental capex through 2020 to replace the Boardman plant with a combination of renewables and peakers. It also assumes POR multiple continues to re-rate higher, at a 2x premium to the regulated peer group. Our upside case further includes 100% probability for a Wind resource build as well as further T&D capex opportunities.

Base (**US $45**): Our **base case scenario** assumes a 0.5x premium to the 2019E peer group multiple. We further incorporate a 50% probability of a Carty 2 as well as a wind resource build equating to ~600Mn of capex through 2020 which is all incremental to mgmt's current plan. Our base case assumes an 8.2% EPS CAGR through 2020 based off the midpoint of mgmts. 2016 guidance.

Downside (**US $40**): Our **downside case** assumes zero probability for $600M of incremental capex through 2020 to replace the Boardman plant and that this is done with **purchase power agreements** (**PPA**) instead. It also assumes no future renewables are rate-based to drive earnings growth 4% or less through the 2020s. Our downside case assumes Portland returns to a discount story among its peers

Portland General Electric Company – Company Description

Portland General Electric Company (POR), was **founded in 1888**, and is a publicly-owned, vertically-integrated, regulated electric utility. POR is engaged in generation, transmission, distribution, and retail sales of electricity in the state of Oregon, serving 840,000 retail customers. POR is also involved in purchasing and selling electricity and natural gas in the wholesale market to obtain power for its retail customers.

Industry Outlook

The electric utility industry is projected to experience **weak or negative electric demand growth** in coming years as a **tepid economy** and **energy efficiency** dampen demand. In the unregulated merchant power space, we see limited potential for a meaningful recovery from currently **low power prices due to limited projected demand growth**, growth of subsidized renewables, and potential for only modest further retirements. At regulated utilities, we believe rising interest rates and robust valuations are a challenge to the sector, particularly as earnings growth stalls once EPA-mandated growth capex slow mid-decade. We **expect cost-cutting** and strategic planning to be a key theme across both regulated and competitive companies, with **M&A at modest** (at best) **premiums** designed to extract cost synergies. We believe **utilities with high parent leverage will disproportionately suffer**, as they are unable to recoup from rising interest rates.

Other Data-Points to Watch:

Changes coming at Commission

We highlight Commissioner John Savage (D) declined to seek another term on the Commission and will be ending his service at the end of this Month. Governor Brown (D) will be appointing Megan Walseth Decker to a term that commences on April 1 (4 year terms). Ms. Decker previously served as the chair of the NW Energy Coalition board. We highlight this is on the back of **new commission** Staff as well.

Oregon Legislation: Less of our Focus

We are less concerned on the 3 pending Senate Bills in Oregon (see a deep dive into each bill here) all which would have a negative outcome for Portland. The closest bill to watch in our view is SB 978 which is slated to be heard March 29th and would disallow IOU's from rate-basing assets greater than 50MW unless there's a unique fleeting opportunity (distressed situation). The associated working group has used Carty and the subsequent construction delays as an avenue for legislative efforts, though we note Coyote Springs, Port Westward, as well as the Tucannon Wind project have all been built on time and on budget.

Equity Needs?

Mgmt noted they **have always tried to have a 50/50 capital structure**, and the RFP may drive them to want a heavier equity layer. This is in line with previous comments as we note mgmt. emphasized on the 3Q16 call that the capex plan can be funded without equity excluding any large resource needs. We emphasize POR currently stands at a 55% equity ratio, and board typically meets in April to discuss dividend policy and capital needs. We have already assumed $150Mn and $100Mn of equity proceeds in 2018E and 2019E, respectively.

Dividend is a Clear Continued Positive Trend

We emphasize the core discussion points are focused on **Dividend Payout** as well, illustrating clear latitude to **continue to grow at a 5-7% pace** despite any execution hurdles, with mgmt. pointing out it is at the **bottom end of its 50-70% range**.

UBS View:

We see POR as more fairly valued following a number data points which challenge the longer dated growth prospects. With the expected benefits from gas peakers / CCGT infrastructure less clear following round of comments from both parties in the IRP docket, there are notably less shots on goal to achieve positive capex revisions. This is paired with a negative NT back-drop on the load growth side following mgmts. negative revisions over the last two years making it increasingly difficult for us to reconcile with LT forecasts embedded in the IRP. Admittedly, proceedings have proved more difficult than initially thought, and have caused some revisions for load needs. Further, we see risk to the **2018 GRC** process, in which **bonus depreciation** could well come up as a **sticking point** among Staff. While further upside could stem from RPS needs via the procurement of an additional wind asset, the **path for further incremental baseload generation is less clear**. We acknowledge that the underlying coal deactivation and RPS requirements help differ POR from SMID peers, but we see the path to full execution as considerably more challenged following 1H17 data points.

Evidence:

Recent commentary from mgmt. reset investor expectations for an additional gas unit to be built at the Carty Generation site. Further, the **IRP** has already seen **push back from OPUC Staff**, causing mgmt. to decrease capacity needs ~300MWs.

What's Priced In?

We see consensus numbers ascribing some probability for future resource builds given our estimates stand only slightly above consensus and **still include 50% probability for Carty Unit 2, and 50% probability for generic wind builds**

PPA's come up as a viable option for capacity needs:

Mgmt recently commented that there are a number of industrial closures in the northwest resulting in lower loads but also idle plants that could allow for existing resources to meet POR's capacity needs at a lower cost than building a Carty Unit 2 or 3. Bilateral negotiations are being pursed between generators and POR over the next 2 to 4 months. We emphasize if mgmt. can indeed contract a PPA to fill capacity needs, incremental capex from a Carty Unit 2 would be foregone. We mgmt. could also acquire assets outright, still presenting a rate-base opportunity though this would **likely prove less profitable than an outright build at Carty**.

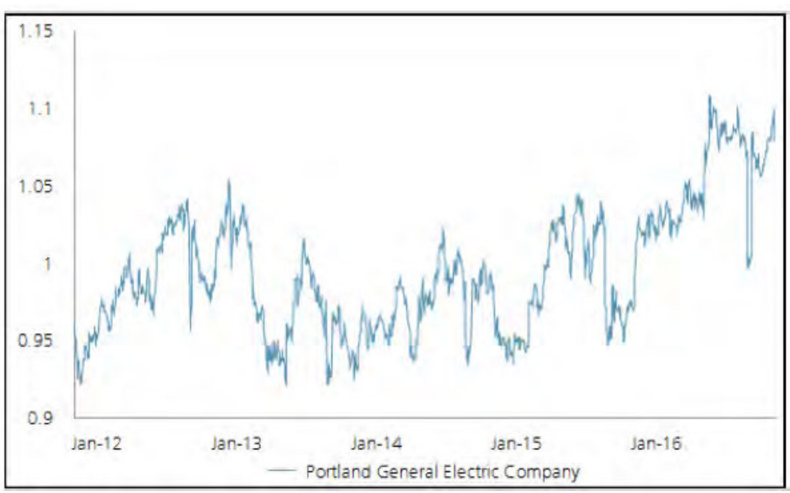
Shares have Traded Well into Potential Catalysts:

We emphasize **shares have outperformed over the last two years** as POR has rerated from a discount story to a premium story, **trading now at an 8% premium** to the XLU. We acknowledge the multiple avenues ahead for capex awards which justifies the premium valuation (we continue to ascribe a slight premium to the group in our P/E based valuation) though execution risks remain. We see the **regulatory environment in Oregon becoming increasingly challenged**, with **Staff most recently responding negatively to POR's asks set forward in the IRP** causing further delays in the RFP process. This would ideally lead to **additional capital spend down the road** in which the **probabilities** are also **decreasing**. Execution remains the largest risk in our view and given the re-rating already experienced **we are downgrading shares** as we see valuation more balanced into 2H17 catalysts.

Figure 1: FY2 (Consensus) – P/E

Source: FactSet

Figure 2: POR FY2 vs. XLU – 5yrs



Source: FactSet

Where can POR FILL THE CAPACITY?

Outside of a competitive build for a Carty Unit 2, we note there are several opportunities for Portland to strike PPAs or purchase rate-base qualified assets across the Northwest. Specifically, we see CPN's Hermiston hydro asset located in Oregon positioned well to participate in either the RFP or contract a PPA. Further, we note AGR's 480MW Klamath gas plant could fit the bill given the proximity of service territory transmission lines as well as our expectation for two major PPA's to roll off in the 2021 period. We note **thermal resources as well as hydro assets are on the table per our latest discussions with mgmt**.

Trading at a premium – long term story is indeed there, but near-term is clouded

What are the difference scenarios forward?

We expect mgmt. to communicate how it plans to fill the ~400MW need in the next few months before the Commission acknowledges the 2016 IRP. We emphasize PGE's final reply comments are due by June 23, 2017 –- we would expect some communication from mgmt. as to how they plan to fill the need on or around this date. Below we delineate the following paths forward to backfill the capacity need.

(1) **Execute PPA with counterparty**: While we acknowledge that determining the most cost effective path forward could well include PPA's, the story has always been positioned towards the likelihood of a 2nd gas unit at Carty. A PPA would be treated as a **pass-through cost rather than an earning asset**, and **could well be a cheaper and more viable option for consumers**. We note this could be deemed the most prudent path forward ahead of a 5.6% cost of service increase request recently filed at the Commission. **If a PPA were to be executed, the Commission would need to grant a waiver**.

(2) **Execute a base-load asset purchase**: We note mgmt. could well rate-base an asset, which would also **need to be acknowledged by the Commission**, though this is likely to be less than the value of a new build at Carty two given the effects of depreciation on net plant.

(3) **Build Carty 2**: We include a **50% probability** of a Carty 2 build which could provide most incremental to our estimates. We see this among the **largest expectation** that was reset following the 1Q17 call given shares meaningfully underperformed the XLU (-1.76%) despite the large qtrly beat. While the existing IRP (pro-forma for the latest drop in load and signed PPAs for hydro) still contemplates sufficient capacity to justify the plant, the risk is either that the plant is delayed (due to demand growth pushed out) and/or it is ultimately contracted externally. We see an **acquisition of an asset and ultimate transfer into rate-base** (for instance of CPN's merchant plant Hermiston to which it remains open to divesting). A sale would likely be done at a discount to the new-build economics of Carty 2, but still provide a modest rate-base opportunity as well.

Updated Capex Estimates

Given recent commentary on the call we're dropping our **probability weighted**

capex estimates for **Carty Unit 2** to **50%** from 100%, equating to slightly lower EPS estimates in 2018 and beyond. We note the **change in tone from mgmt**. despite recent commentary on the road discussing a competitive build at Carty 2 resets our expectations for incremental resource needs. We continue to ascribe a **50%** change of **Generic Wind** given the need to satisfy RPS standards. We continue to look for positive updates to the capex schedule later this year with additional expansion of substations, likely with 3Q.

Figure 3: POR Probability Weighted Capex Estimates:
Shifting Probabilities and Timing of Capex

Capital Expenditure $MM	UBSe	2016A	2017E	2018E	2019E	2020E	2021E
Base Spending	Probability	$407	$585	$446	$294	$303	$290
Port Westward	embedded						
Tucannon	within capex						
Carty		$197	$6				
UBSe: (Above Guidance)							
Carty - Unit 2	50%			$28	$113	$28	
Port Westward - Next Unit	0%				$0	$0	
Next Generic Wind - for 2020 RPS	50%			$213	$213		
Gas Reserves	0%		$0	$0			
RPS Renewable opps (if OR goes to 50% by 2030)	25%					39	$39
RPS CCGT opps (if OR goes to 50% by 2030)	25%						
Other T&D Projects incl Undergroudning				$50	$50	$50	$50
Total Capital Expenditure		**$604**	**$591**	**$737**	**$669**	**$421**	**$421**
Depreciation		$321	$341	$354	$375	$390	$392
Current mgmt guidance 1Q17 slides			*$585*	*$446*	*$294*	*$300*	*$290*

Source: UBSe, Company Filings

Capex Estimates vs Current Guidance – Already Ahead Mgmt.

We emphasize we already stand considerably above mgmts. capex forecasts due to our probability embedded scenarios. We see the next capex update slated for the 3Q17 earnings call or EEI, typically following approval from the Board of Directors which could well include further T&D related spend. We note **substations and cable undergrounding** remain the primarily source of **organic upside,** though this likely is not enough to address the step down shown in guidance in 2019 and beyond.

EPS Estimates: Lower on Probability Weighted Outcomes

We are shifting our EPS estimates $0.02/0.05/0.04 lower for 2018/2019/2020 to **account for** the ~$168Mn **capex revision in our model**. We emphasize the recent $0.28 weather impact on the qtr largely masked an ($0.08) weather adjusted load impact (net of 2 cents for energy efficiency) which further alludes to the impact load trends are having on core EPS in our view. **We see** latitude for **estimates** to be **revised lower if** the **prospects** for **incremental builds** continue to **deteriorate**.

Figure 4: Updated EPS Estimates – Slightly Above Consensus (FactSet / Filings)

	2012A	2016A	2017E	2018E	2019E	2020E
UBS EPS estimates		$2.17	$2.29	$2.51	$2.56	$2.69
UBSe CAGR						5.2%
Prior UBS EPS estimates		$2.17	$2.29	$2.53	$2.60	$2.73
Street Consensus EPS (FactSet)		$2.16	$2.27	$2.46	$2.55	$2.70
Management Guidance - EPS		2.05-2.20	2.20-2.35			
DPS	$1.07	$1.26	$1.35	$1.44	$1.54	$1.64
DPS Growth (quarterly, usually in 2Q)		$0.020	$0.0225	$0.0225	$0.025	$0.025
Dividend Payout Ratio (UBSe)	57%	58%	59%	57%	60%	61%
Management Guidance - Payout		50-70%	50-70%			
DPS growth	2%	7%	7%	7%	7%	7%
Management Guidance - Dividend growth		5-7%	5-7%			

Valuation: Downgrade to Neutral – PT $2 lower to $45

We include our latest P/E based valuation below. We are dropping our premium multiple by a half turn given the increasingly challenged regulatory environment we see in Oregon. Our valuation methodology is based on a 2019E peer group (see appendix for full peer set). Changes in our price target are due to lower 2019 Eestimates ($0.70/sh) and a lower premium multiple ($1.28/sh).

Figure 5: POR Valuation

Business Segment	Valuation Metric	2019 EPS	Low Case Valuation Multiple	Low Case ($ MM) Value	Base Case Peer Multiple	Base Case Prem/(Disc) to Peer	Base Case Base Multiple	Base Case ($ MM) Value	High Case Valuation Multiple	High Case ($ MM) Value
Portland General Electric Company	P/E	$2.56	15.8x	$40	17.3x	0.5x	17.8x	$45	19.8x	$51

Source: FactSet, UBSE, Company Filings.

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UBS Downgrades Portland General Electric to 'Neutral'

by Nephele Kirong – SNL Financial LC – May 2, 2017

UBS Securities LLC lowered its investment rating on Portland General Electric Co. to "neutral" from "buy" on a dimmer view of the profitability of the company's efforts to fill capacity needs.

"The path forward is less clear to us given execution woes through the 2016 [integrated resource plan] including a guide down on capacity needs, a challenging load forecast picture, as well as decreased prospects of outright ownership of new generation assets," analyst Julien Dumoulin-Smith said in a May 2 investor note.

During PGE's first-quarter 2017 earnings call, company executives revealed that they are pursuing bilateral negotiations with several power plant owners in the Northwest for a cheaper means of fulfilling expected capacity deficits.

The company revised its 2016 IRP to include a lower capacity deficit forecast of 561 MW instead of the previous 850 MW.

As such, Dumoulin-Smith also revised his 12-month price target on the company to $45 from $47 and his full-year EPS estimates to $2.51 from $2.53 for 2018 and to $2.56 from $2.60 for 2019. The analyst is keeping his full-year 2017 EPS estimate at $2.29.

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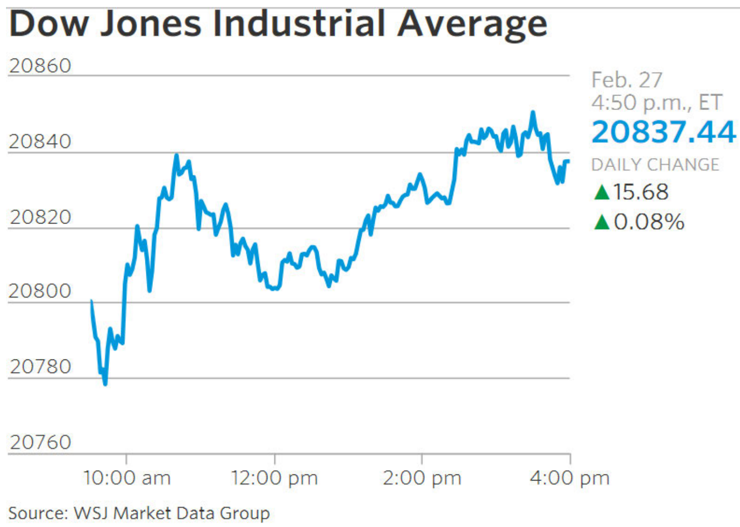
Search for Yield Buoys Utilities Stocks

by Corrie Driebusch and Riva Gold — WSJ — Feb. 27, 2017



Major indexes spent most of the session in the red before a buying spree in the last half-hour of trading drove shares higher

Utilities companies posted their best weekly performance since July as **investors poured money into dividend-paying stocks alongside a rally in bonds**.

Major U.S. stock indexes spent most of Friday with declines, before a buying spree in the last half-hour of trading buoyed shares. The Dow Jones Industrial Average fell as much as 76 points before closing up 11.44 points, extending its streak of records to 11 consecutive days.

It is the longest streak of records for the blue-chip index since 1987.

A drop in government-bond yields sent money into stocks with relatively high dividends. Bonds strengthened for a third consecutive session, with the yield on the **10-year Treasury note slipping to 2.317%** — its lowest since late November.

Utilities companies in the S&P 500 rose 4% over the week, the best performance since the week ended July 1 for the sector, which has a dividend yield of 3.5%, according to FactSet.

The drop in yields pressured banks. Lower interest rates can hurt lenders' profits by narrowing the gap between what they pay on deposits and what they charge on loans.

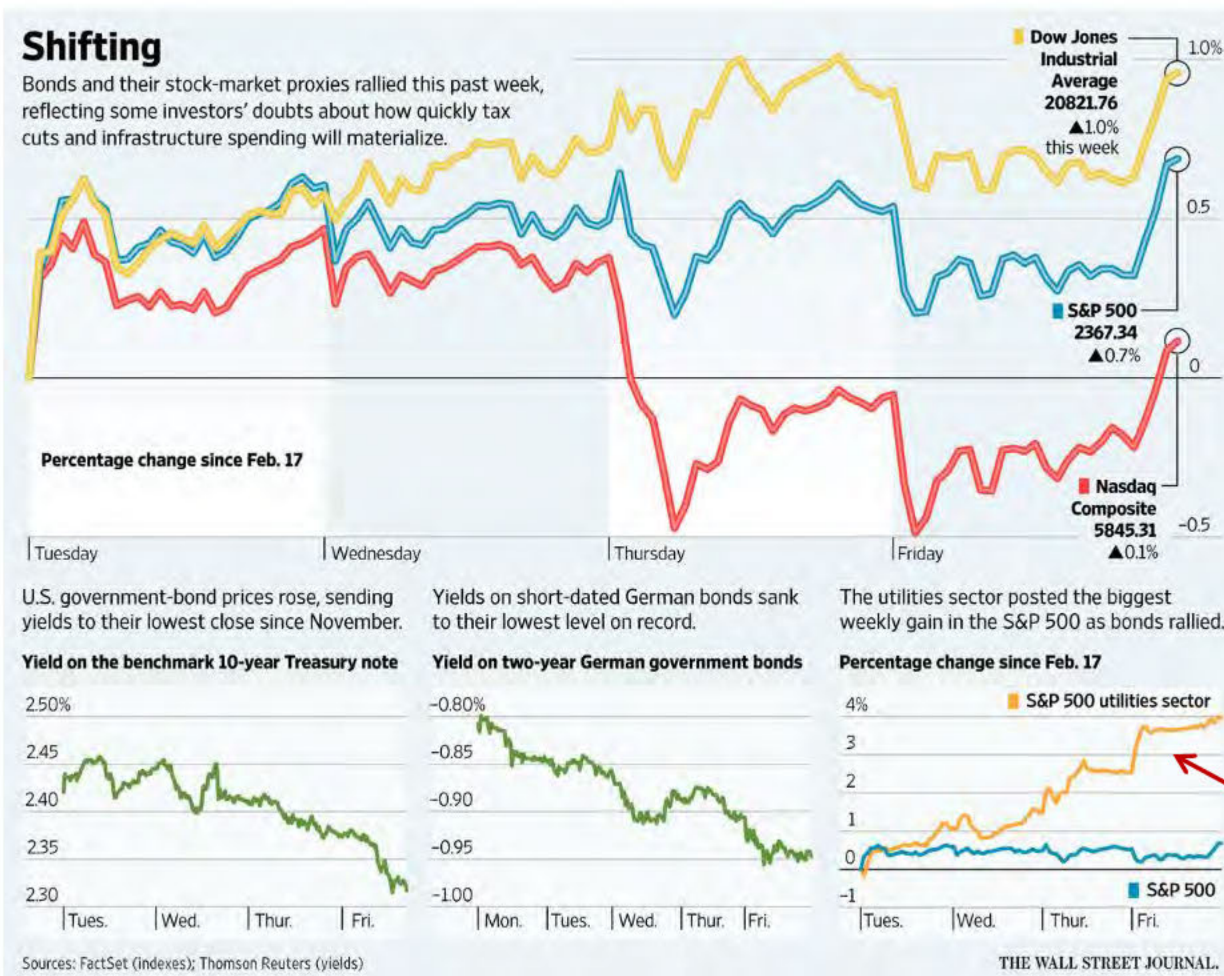
Financial companies in the S&P 500 lost 0.8% on Friday, putting their weekly loss at 0.1%. Morgan Stanley fell $1.05, or 2.3%, to $45.53, Citigroup lost 1.06, or 1.7%, to 59.56, and MetLife fell 1.07, or 2%, to 52.49.

The S&P 500 rose 3.53 points, or 0.1%, to 2367.34 on Friday, and the Nasdaq Composite added 9.80 points, or 0.2%, to 5845.31. The Dow industrials rose less than 0.1% to 20821.76. It was the third straight week of gains for the Dow, and the fifth consecutive positive week for the S&P 500 and Nasdaq Composite.

Expectations for tax cuts, infrastructure spending and relaxed regulations have lifted stocks since Election Day. But enthusiasm for stocks slowed on skepticism about how quickly these policies can be enacted. Many investors are now waiting for Mr. Trump to address Congress on Tuesday, when he might offer further details on his policy intentions.

At the same time, trading volumes have been relatively low compared with last year. An average of 6.7 billion shares have changed hands each day in 2017, according to the WSJ Market Data Group. That falls below the average of roughly nine billion shares a day in the same period last year.

The Dow industrials have risen 5.4% so far this year, while the S&P 500 has climbed 5.7%, and the Nasdaq has added 8.6%.



Hewlett Packard Enterprise fell 1.70, or 6.9%, to 22.96, after the company lowered its outlook for the year and reported a steep drop in quarterly revenue.

Foot Locker rose 6.43, or 9.4%, to 75.01 after the retailer reported better-than-expected earnings in the fourth quarter.

U.S.-traded crude oil for April delivery declined 0.8% to $53.99 a barrel, dragging down shares of energy and mining companies on Friday.

Energy companies in the S&P 500 fell 0.9% and were among the worst performers in the broad index.

For the week, the price of crude oil ticked up 0.4%, though energy stocks in the S&P 500 ended the week down 1.3%.

Gold, the yen and government bonds climbed, supported by fading expectations that the Federal Reserve would raise interest rates in March and uncertainty around U.S. fiscal policy.

The price of gold rose 0.5% on Friday, ending the week up 1.6% at $1,256.90 an ounce.

The Stoxx Europe 600 declined 0.8% Friday, as a fall in commodity prices and lackluster corporate earnings wiped out gains for the week.

Bank shares fell after Royal Bank of Scotland Group and Standard Chartered reported 2016 results, while shares of German chemicals company BASF and French media company Vivendi also dropped.

Concerns about delays to U.S. stimulus measures and falling bond yields hampered Asian markets Friday. Hong Kong's Hang Seng Index fell 0.6% to end the week lower.

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Sentiment vs. Reality: The Economy Is Telling Two Different Stories

by Steven Russolillo — WSJ — Mar. 30, 2017

The difference between what people say about the economy and actual economic performance is at a record.

How is the Economy Doing?

Based on surveys alone, one would think it is booming. **Consumer confidence soared to a 16-year high** in a Conference Board poll released this week. **Surveys** of **small-business owners** reflected optimism since the election. Chief **executives** of the largest U.S. companies say they are **more optimistic now** than at any point in the past seven years, according to a Business Roundtable survey.

But just because people say they are optimistic doesn't mean everything is great again. What Morgan Stanley economists call the **"hard, quantifiable data" tell a much different story**.

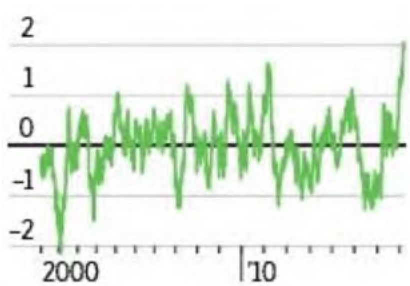
The **economy finished last year growing at just a 2.1% annualized rate**, **consistent with** what has been the **weakest expansion in the post-World War II era**. **Business spending remains lackluster**, **retail sales slowed in February** and, after a banner 2016, auto sales have since struggled.

More hard data are due Friday morning with the Commerce Department expected to release updates on income, spending and inflation. Personal income reflects Americans' pretax earnings from salaries and investments.

Economists polled by The Wall Street Journal estimate personal income in February rose 0.4% month over month, matching January's percentage gain. Consumer spending is expected to have gained 0.2% in the same period, also matching the increase in January. Both estimates reflect gains that are decent but far from robust. The personal-consumption expenditures price index, the Federal Reserve's preferred inflation gauge, is getting closer to the central bank's 2% annual target.

Survey Says:

Spread between "soft" consumer-sentiment metrics and "hard "economic data



Note: Based on components of Bloomberg U.S. Economic Surprise Index
Source: Morgan Stanley Research

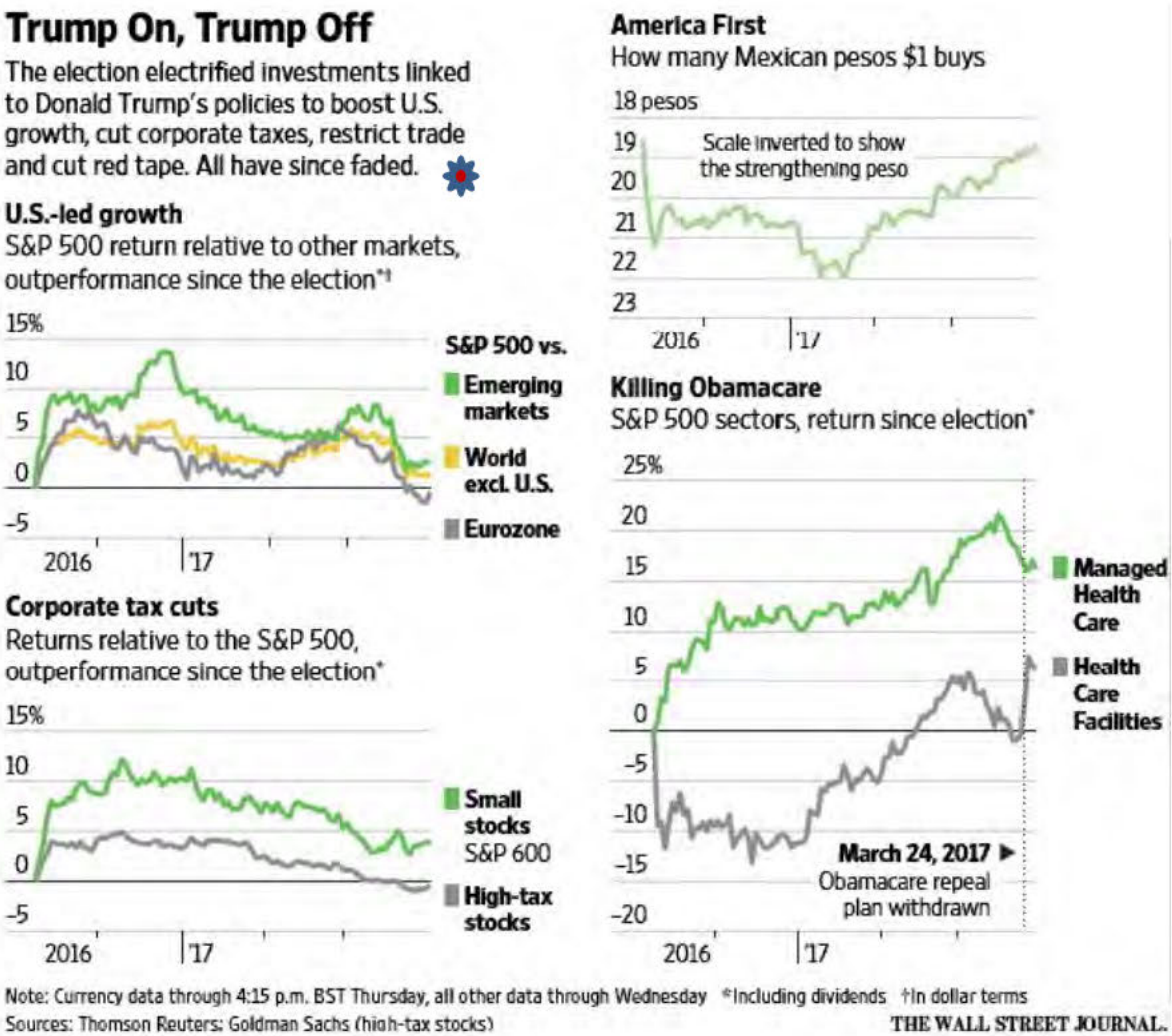
The difference between what people say about the economy and actual economic performance is a phenomenon that Morgan Stanley economists highlighted in a report this week. **Soft sentiment data have surged while the hard economic metrics haven't budged much**.

"The divergence is stunning," Morgan Stanley wrote to clients this week, noting the spread between hard and soft economic data is at an a record. Either confidence will start waning or it will fuel a material uptick in economic output. That is why Friday's reports deserve a close look.

On the bright side, a consumer-spending measure was revised higher in the third and final update of fourth-quarter U.S. gross domestic product, released Thursday. If improvement in spending is sustainable, it will need to be supported by continued gains in statistics such as income and jobs.

But with the first quarter concluding Friday, **economists continue to have muted expectations**. Those polled by Macroeconomic Advisers expect just 1.6% growth, lower than average through the current recovery.

Something has to give.



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Trump Team's Growth Forecasts Far Rosier Than Those of CBO, Private Economists

by Nick Timiraos — WSJ — Feb. 17, 2017

While there are **often disparities between** the **White House and independent agencies on growth projections**, they are **rarely this large**


President Donald Trump walks to Marine One on the South Lawn of the White House

The **Trump administration has drafted preliminary economic growth forecasts** in its **federal budget planning that rely on assumptions that are far rosier than projections made by independent agencies and most private forecasters**, according to several people familiar with the discussions.

The forecasts are being revised, these people said, following an internal debate. One concern is that pressing staff economists to produce aggressive forecasts might undercut the credibility of top appointees forced to later defend those numbers.

The deliberations show the challenge the administration faces as it tries to reconcile the competing goals of cutting taxes, boosting military and infrastructure spending, preserving Medicare and Social Security programs and keeping budget deficits from soaring

Economic growth forecasts are presented as part of White House budget submissions to Congress and are **due out from the Trump team in the coming weeks**. They have an important impact on projected debts and deficits. A fast-growing economy produces more revenue while reducing the need for spending on programs such as food stamps or unemployment insurance. Fast growth estimates can thus hold down projected deficits.

The forecasts, which were initiated before President Donald Trump took office, project gross domestic product — a broad measure of national output of goods and services — growing **between 3% and 3.5% a year over the coming decade**, with inflation-adjusted annual growth ultimately **settling at around 3.2% during the later years of the 10-year forecast**.

The **economy has grown around 2% on average over the past decade**. **Many economists believe sustained growth at more than 3% will be difficult to achieve without a sharp rebound in productivity growth and a reversal in the slowing expansion of the U.S. labor force**, **developments few are projecting**. **Worker**

productivity growth has slowed to 0.7% a year since 2010, a sharp slowdown from rates exceeding 3% in the late 1990s and early 2000s.

The **internal Trump projections are at odds with other assessments of the** economy's long-run growth prospects. The **Congressional Budget Office, a nonpartisan agency that provides analysis to Congress, estimates the economy will grow 1.9% annually between 2021 and 2027**. The **Federal Reserve forecasts growth of 1.8% over the long run**. While there are often **disparities** between the White House and other agencies on growth projections, they are **rarely this large**.

"The president ran a campaign on proposals that would be **incredibly pro-growth**," said Lindsay Walters, a White House spokeswoman. "There is a process in place where the administration develops an economic forecast based on its policies that are included in the president's budget. That **budget is still being finalized**."

During the campaign, **Mr. Trump** made apparent his **low regard for economists**. His administration has yet to name any of the three members to his Council of Economic Advisers, which oversees forecasting and other modeling.

The forecasts were prepared by Trump transition officials who met with officials at the Treasury Department and the CEA after the election, according to five people familiar with those discussions.

"It is awfully hard to get to 3%. I don't know where a number like that would come from," said **Dale Jorgenson**, a **Harvard economics professor** who specializes in such projections. Mr. Jorgenson's **most recent forecasts show an economy growing by 1.8% annually over the next decade**. That's in part because the labor force is aging, meaning there are fewer workers to produce goods and services, and because the **educational attainment** of the **workforce** has **plateaued**, meaning **workforce skills aren't advancing**. **Major policy changes such as a tax-code overhaul could boost growth to 2.4%**, he said.

Trump officials believe a regulatory rollback and a tax-code revamp will unleash growth that drives a recovery in productivity, sends business investment higher and draws idled workers back to the labor force. They also assume interest rates would remain low because the U.S. would become a more attractive place to park money.

The higher annual growth estimates in the initial internal Trump forecasts would result in the U.S. economy becoming 17% larger after a decade relative to recent projections from the CBO, which produces forecasts that assume no changes to current tax and spending policies.

The higher growth assumption in the Trump forecast would show sharply lower deficits as a share of gross domestic product, especially in the back half of the 10-year forecast window.

Maya MacGuineas, president of the Committee for a Responsible Federal Budget, a group that advocates deficit reduction, said Mr. Trump's policies to boost spending on the military and to cut taxes are likely to increase deficits.

"The risk is that rosy economic scenarios allow us to borrow trillions of additional dollars in the next couple of years, doing real damage" if growth doesn't materialize, she said.

Republicans in Congress won't be able to rely on such estimates when they produce a budget resolution for the coming fiscal year because they use estimates from the CBO.

Boosting growth faces other challenges. It is possible the Fed would move faster to raise interest rates in order to prevent the economy from overheating if growth began to accelerate and stirred inflation. The Fed has raised short-term rates twice since 2015 and plans more moves in the months ahead.

The internal growth projections struck some people who saw them as **extraordinarily optimistic** because they **assumed inflation would remain low and interest rates wouldn't increase much beyond policy makers' current expectations despite the big growth spurt**.

Mr. Trump campaigned on some policies that could raise other hurdles to growth, particularly limiting immigration. **Net immigration currently accounts for nearly all of the growth of the working-age population, an important underpinning of economic growth**. "**If you slow the immigration rates a bit, it's going to cost you in terms of growth**," **said Mr. Jorgenson**.

What's unusual about the administration's forecasts isn't just their relative optimism but also the process by which they were derived. Normally, the executive branch starts with a baseline forecast prepared by career staff of the CEA.

Officials then calculate how their policy changes add or subtract to that forecast. Those exercises are managed by the so-called **troika**—top political appointees at the **CEA, the Treasury Department and the White House budget office**. The heads of each department make final signoffs.

Discussions for the Trump administration unfolded differently, with transition officials telling the CEA staff the growth targets that their budget would produce and asking them to backfill other estimates off those figures.

These projections could shift as top personnel at key agencies take their jobs. The **Senate confirmed Steven Mnuchin as Treasury secretary on Monday** and **Mick Mulvaney as White House budget director on Thursday.**

"The biggest thing I'm surprised about is they don't have the people in place to do this," said Douglas Holtz-Eakin, who served as an economist in both Bush administrations before leading the CBO. No one is at the CEA, so how is this getting done?"

All presidents put a positive spin on the growth effects of their policies, allowing them to project higher growth than independent forecasts. **In January 2016, for example, the CBO said the economy would grow 2% annually between 2021 and 2025. The Obama administration said a few weeks later that if all of its proposed policies were adopted, GDP would rise 2.3% over the same period**.

One person involved in several previous budget processes said he had never seen career staff asked to make such aggressive assumptions about economic growth as during the new administration. Several people involved in past budget deliberations said those discussions have usually centered on whether **growth would be one or two-tenths of a percentage point higher than other estimates, not a full percentage point**.

Republicans and Democrats in prior administrations said presidents have typically been hesitant to produce implausibly glowing projections because it could weaken their credibility with Congress and the public.

"A fair amount of time and energy is spent making sure the forecast is internally consistent," said Mr. Holtz-Eakin.

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Trump's Growth Target Looks Out of Reach

by Greg Ip – WSJ – Capital Account Newsletter – May 22, 2017

Great leaders, whether of sports teams, companies or countries, set audacious goals to spur followers on to great accomplishments. But the goal isn't enough: A leader also needs a credible path to achieve it.

That's the problem with **President Donald Trump's first budget**. It sets a worthy objective of **sustained 3% economic growth**, **but** offers **no rigorous plan to back it up**.

To listen to budget director Mick Mulvaney, the main thing holding the U.S. economy back is a bad attitude. Projections by the previous administration and the Congressional Budget Office of 1.9% long-term growth were "sad," he said Monday. "That assumes a pessimism about America, about the economy, about its culture, that we're simply refusing to accept. We believe that we can get to 3% growth and we don't believe that's fanciful."

Mr. Trump — moving in the opposite direction of President Barack Obama — promises lower taxes and less regulation, which should increase business investment and thus worker productivity. Moreover, a less-generous social safety net could prod some people back to work. **More workers who are more productive are the ingredients of faster growth**.

Yet there are good reasons independent economists think the U.S. can't return to its historic growth of 3%. The **U.S. working-age population grew 1.2% a year from 1950 through 2000**. **With** the **baby boomers retiring** and **families shrinking**, it will **grow less than 0.3% a year over** the **next decade**. To make a credible case for 3% growth, Mr. Trump has to identify some wellspring of workers or productivity that his predecessors have missed.

Mr. Mulvaney thinks prodding many people off social safety-net programs and back to work will be good for them, and for growth.

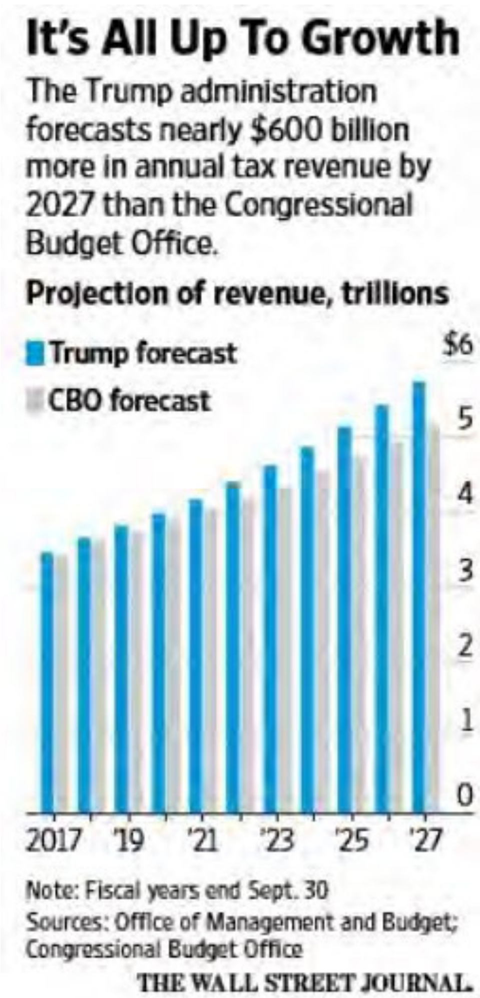
In principle, that's true, but the magnitudes are doubtful. About half of household heads on food stamps and three quarters of those on Medicaid already work, says Robert Moffitt, an economist at Johns Hopkins University. At most, 13 million recipients of Medicaid and 6.5 million recipients of food stamps don't work (and the two groups overlap). The growth of people on disability insurance can be slowed with tougher eligibility, but experience suggests getting existing recipients off is almost impossible.

When welfare was cut off in the 1990s for single mothers able to work, the share of those not working dropped by up to a third. That kind of effect on 13 million Medicaid recipients or 6.5 million food-stamp participants would generate only a modest, and one-off, boost to a labor force of 160 million. The effect on gross domestic product would be even more muted because, Mr. Moffitt notes, these workers have extremely low skills and thus productivity.

Nor would repealing the Affordable Care Act do the trick. The CBO estimates its health-insurance subsidies, which become less generous as wages rise, discourage work and would eventually reduce employment by 2 million. But little of that has been felt yet, and the Republican replacement plan maintains some of those subsidies.

One safety-net reform that would meaningfully expand the labor force would be a higher retirement age for Social Security and Medicare. But Mr. Trump promised not to touch either and his budget, it declares, "does not."

Lowering corporate tax rates in theory would make many more capital projects profitable, bolstering productivity meaningfully. But the budget doesn't include a tax reform plan. It merely assumes reform will be "deficit neutral," then extrapolates today's tax take, as a share of GDP, out for the next 10 years Mr. Trump has proposed steep cuts to personal and corporate tax rates that even optimists think will add trillions to the deficit. The Tax Foundation, a pro tax-cut think tank, reckons lowering the corporate rate to 15% as Mr. Trump wants would only raise growth to 2.3% from 1.9%, and that boost would peter out once all the newly profitable capital projects had been undertaken.



Mr. Trump is intent on limiting regulation. As with taxes, this goes in the right direction, but the benefits are potentially slim.

Sam Batkins of the American Action Forum, a conservative think tank, says the administration has already slowed the production of new rules, but repealing significant rules is hard because it requires Congress.

Presidents are supposed to be optimists. But much is at stake with this one. Many of his other promises rely heavily on the 3% growth goal. For example, the budget is supposed to balance by 2027, with the help of nearly $600 billion a year in added revenue attributable solely to a more aggressive growth forecast. **Until Mr. Trump presents a credible vision for achieving that growth, the rest of his promises are best viewed with deep skepticism**.

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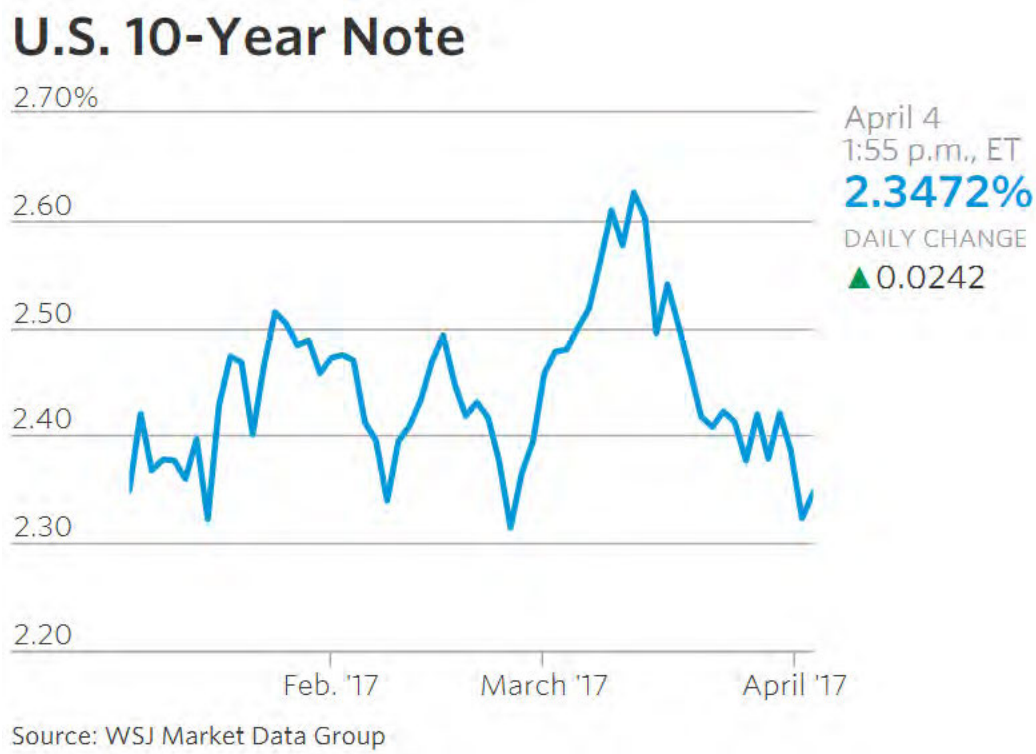
U.S. 10-Year Yield Hits Lowest Point in Over a Month

by Min Zeng — WSJ — Apr. 4, 2017



Multiple concerns have investors running to the safety of government debt.

U.S. government bonds strengthened for a third consecutive session, with the yield on the benchmark 10-year Treasury note falling to the lowest level in more than a month.

Traders cited a number of factors that continue to support the bond market: **skepticism toward President** Donald **Trump's capability** to push through a large fiscal stimulus; a **Federal Reserve** that is slow **in raising short-term interest rates**; and **uncertainty surrounding** the **French presidential race later this month**.

The **yield** on the benchmark **10-year Treasury note** fell to **as low as 2.314%** earlier Tuesday morning, the lowest intraday level since Feb. 24, according to Tradeweb. Yields fall as bond prices rise.

The buying has eased since then, with the yield recently trading at 2.339%, compared with 2.351% on Monday.

Selling Treasurys has been one of the highlights for investors **since** the **election** as **investors placed bets** that a **sizable** fiscal **stimulus** would lead to **stronger growth** and **higher inflation**.

But **bets on higher bond yields**, known as **shorts**, **have been falling sharply over the past few weeks**. Net wagers betting on higher bond yields via Treasury futures contracts were $54.2 billion for the week that ended March 28, according to TD Securities. It was the lowest since Nov. 22. The net shorts had reached $100.7 billion in early January, the highest since 2008.

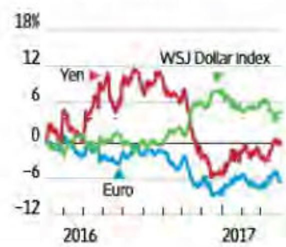
Todd Colvin, senior vice president at Ambrosino Brothers, said **investors** are **moving from** the **Trump trade toward** the “**what if**” trade.

Treasury yield curve

Yield to maturity of current bills, notes and bonds

Forex Race

Yen, euro vs. dollar; dollar vs. major U.S. trading partners



Sources: Ryan ALM; Tullett Prebon; WSJ Market Data Group

Specifically, he explained that investors are reshuffling their market positions as they face questions including: **what if tax reform doesn’t pass**; **what** if the U**.S. growth remains sub-2%**; **what if inflation remains low**; and **what if** the **European elections result in** a **surprise**?

Corporate Borrowing Rates and Yields

Bond total return index	Close	Yield (%) Last	Yield (%) Week ago	52-Week High	52-Week Low	Total Return (%) 52-wk	Total Return (%) 3-yr
Treasury Ryan ALM	1438.909	**2.016**	2.038	2.237	1.141	**−1.768**	3.088
10-yr Treasury, Ryan ALM	1710.388	**2.351**	2.373	2.609	1.366	**0.507**	3.407
DJ Corporate	365.458	**3.147**	3.197	3.390	2.460	**1.903**	3.938
Aggregate, Barclays Capital	1870.380	**2.590**	2.600	2.790	1.820	**−0.633**	2.372
High Yield 100, Merrill Lynch	2754.306	**5.480**	5.737	6.921	5.200	**13.309**	3.178
Fixed-Rate MBS, Barclays	1854.690	**2.910**	2.900	3.120	1.930	**−4.456**	1.155
Muni Master, Merrill	506.327	**2.136**	2.124	2.516	1.297	**−0.165**	2.966
EMBI Global, J.P. Morgan	768.658	**5.689**	5.662	6.290	5.134	**8.838**	5.713

Sources: J.P. Morgan; Ryan ALM; S&P Dow Jones Indices; Barclays Capital; Merrill Lynch

The **10-year yield had jumped** from 1.867% settled on Nov. 8, U.S. **election day**. **But** it has been **sliding after rising above 2.6% last month** and reaching the highest point since Sept 2014.

Some analysts say Treasury bonds represent an opportunity to sell to lock in profit with the yields now trading near the bottom of a 2.3-2.6% range, a band that has prevailed over the past four months.

The share of investors expecting higher yields, or shorts, rose to 23% for the week that ended Monday from 20% a previous week, according to J.P. Morgan’s Treasury client survey released Tuesday. The share of those expecting lower yields, or longs, is steady at 16%. The gap—a net short of negative 7%—is the largest since Feb 21. That suggests the most bearish sentiment in more than a month.

This week’s key data point is the nonfarm jobs report due Friday. The Federal Reserve is scheduled to release the minutes for its March meeting on Wednesday.

Political risk in **Europe** has also **raised** the **appeal** of **haven assets**.

The first round of presidential election in France will take place on April 23. A right-wing candidate has been calling for France to pull out of the eurozone. The anti-euro platform has raised anxiety among **investors** and drove them to hedge the muddy outlook. One way is to sell French government bonds and **allocate** the **cash into** safer government-bond markets in **Germany and** the **U.S.**

As **investors** are **shunning French government debt**, the yield premium on the two-year French government debt relative to comparable German government debt has reached the highest point on Tuesday since 2012.

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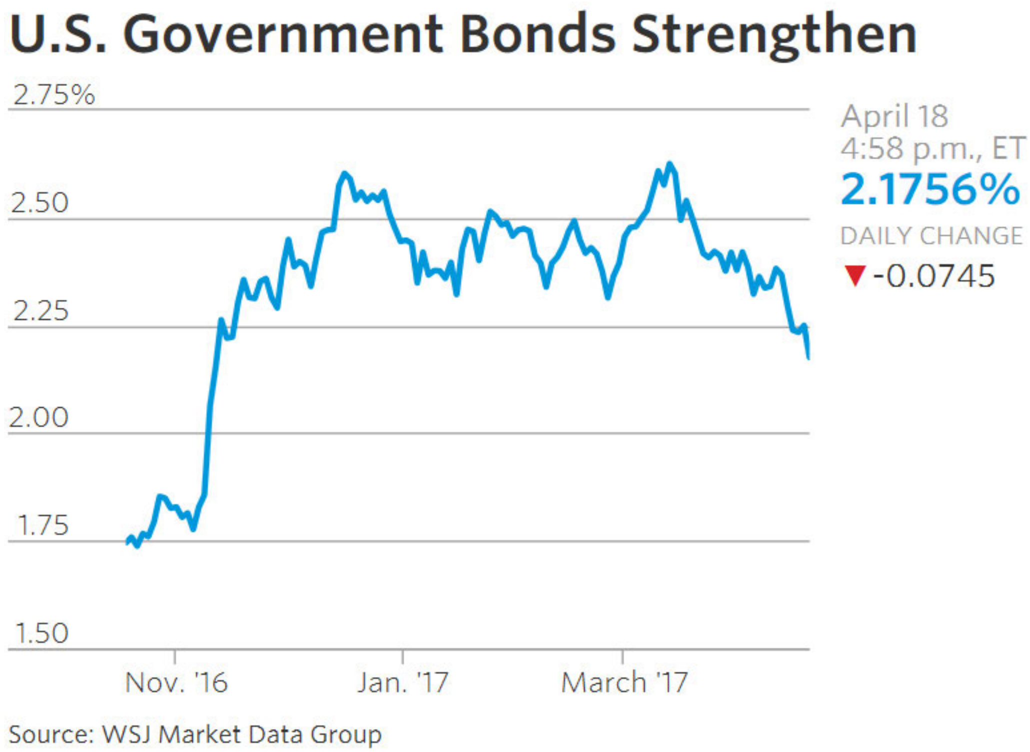
Treasurys Rebound on Political Uncertainty
by Sam Goldfarb — WSJ — Apr. 18, 2017

The yield on the 10-year Treasury note settles at 2.177% in lowest close since Nov. 10



U.S. government bond yields resumed their steep decline Tuesday as political uncertainty drove investors to buy haven debt again after a brief hiatus Monday.

The **yield on the benchmark 10-year note settled at 2.177%**, compared with 2.248% Monday. That was its **lowest close since Nov. 10, two days after the U.S. presidential election**, **though still well above its Election Day close of 1.867%.**

Yields, which **fall as bond prices rise**, have declined fairly steadily over the past month because of a confluence of **factors**, including **geopolitical risks in North Korea and Syria,** uncertainty surrounding the **French presidential election** and f**ading optimism that Congress can pass fiscal stimulus measures that could provide a boost to growth and inflation**.

Government bonds got some added support early Tuesday on the news that U.K. Prime Minister Theresa May would make an unexpected statement at 11:15 a.m. London time. The ultimate announcement that Mrs. May would call an early general election on June 8 proved something of a relief to investors, briefly pushing yields higher.

If voting follows recent opinion polls, Mrs. May's Conservative Party could expect to significantly increase its majority in the House of Commons. That could strengthen Mrs.

May's hand as she negotiates an exit from the European Union but wouldn't mark a major change in the political landscape, analysts said.

Still, **other developments continue to boost demand for haven assets**. The **first round of the French election will be held Sunday**. Two candidates go forward into the second round on May 7, and polls suggest a close race between four candidates, including the **far-left** Jean-Luc Mélenchon and **far-right** Marine Le Pen who are **both critical of the European Union**.

Analysts expect a strong rally in Treasurys if both of those candidates make it to the second round, while other outcomes could have a negative or neutral impact on the market.

Meanwhile, there is also political uncertainty in Washington, where lawmakers will have a few days to continue funding the federal government next week after returning from a break.

Though most analysts don't expect a government shutdown, in the unlikely event that it does happen, investors would "significantly mark down their expectations of any stimulus," Michael Cloherty, head of U.S. interest-rates strategy at RBC Capital Markets.

The 10-year yield briefly topped 2.6% in mid-March. Last week, it declined 0.138 percentage points, its biggest one-week slide since June 2016.

Some investors have resisted the urge to buy Treasurys in recent weeks, betting that political and economic conditions haven't changed as much as the market would suggest.

While U.S. economic data has been mixed of late, Federal Reserve officials are still signaling more interest-rate increases this year. They have also started to discuss reducing the central bank's balance sheet, which would open a second front in their effort to gradually tighten monetary policy.

Along with higher inflation, tighter monetary policy is one of the main threats to government bonds.

"You have these French elections, but at the same time the outlook in Europe is a bit better" from an economic standpoint, said Scott Kimball, senior portfolio manager at Taplin, Canida and Habacht, a subsidiary of BMO Global Asset Management.

Over time, decent economic data should lead to more restrictive monetary policies, causing yields to rise, he added.

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Utilities Steady As Broader Markets Dip on Political Uncertainty

by Brian Colins, Charlotte Cox & Dan Lowrey – SNL Financial LC – May 19, 2017

Utilities outperformed broader market indexes in the week ended midday Friday as news released Wednesday on turmoil in Washington sent major indexes to their biggest decline in eight months.

On Wednesday, the DJIA lost 373 points (1.8%), the S&P 500 fell 44 points (1.8%) and Nasdaq dropped 159 points (2.6%) after reports surfaced that President Donald Trump had allegedly asked then-FBI Director James Comey to discontinue an investigation into former National Security Adviser Michael Flynn. The news triggered a global equity sell-off and prompted concerns about the future of Trump's economic agenda. **Investors clung to safety** measures as the DJ Utility Average remained unchanged in trading Wednesday.

Utility stock price performance

	% change	
Top performers	**Week**	**YTD**
Public Svc Enterprise Group	2.8	0.2
Exelon Corp.	2.5	-1.4
NextEra Energy Inc.	1.3	14.9
Ameren Corp.	1.2	5.9
Avista Corp.	1.0	4.3
Bottom performers		
Southwest Gas Holdings	-2.5	1.2
FirstEnergy Corp.	-2.2	-9.3
MGE Energy	-1.8	-3.1
AES Corp.	-1.8	-4.2
PNM Resources Inc.	-1.8	5.8

Prices are through midday Friday.
Source: SNL Energy, an offering of S&P Global Market Intelligence

For the full week through midday Friday, the DJ Utility Average was up 0.2% compared to losses of 0.3%, 0.2% and 0.3% for the DJIA, S&P 500 and Nasdaq, respectively. Year-to-date the DJ Utility Average is up 6.3%, slightly below the 6.6% gain by the S&P 500.

Bond yields weakened as investors also fled to the safety of fixed income in debt markets. The yield on the **10-year Treasury note dropped to 2.2%** from 2.3% last Friday. **By comparison, the average dividend yield on an RRA-covered utility** was **100 basis points higher at 3.2%**.

Top performers

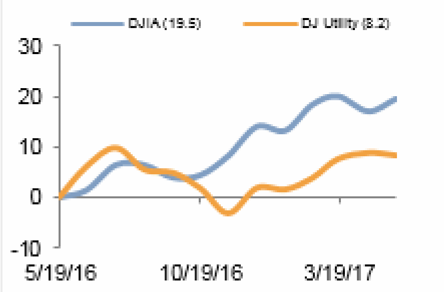
Public Service Enterprise Group Inc. gained 2.8% and was the best-performing RRA-covered utility this week in trading through midday Friday. The gains follow four straight weeks of declines for PSEG. Among its peers, PSEG ranks among the highest in return on total capital during the 12 months ended March 31, 2017. Read our full report on utility financial quality measures here.

Exelon Corp. gained 2.5% during the week, but remains one of the few utility stocks in negative territory in 2017; the shares are down 1.4% year-to-date. On Thursday, Texas-based competitive power supplier Vistra Energy Corp management indicated they were eyeing distressed generation acquisitions in ERCOT, the region Exelon is looking to shed its 3,476 MW of combined cycle gas-fired portfolio.

NextEra Energy Inc. rose 1.3% this week. On May 18, the **Texas Public Utility Commission <u>postponed</u> consideration of NextEra's request for rehearing** of the PUC's April 13 **order rejecting NextEra's proposed acquisition of <u>Oncor</u> Electric Delivery Co. LLC**. The parties have **until May 23 to comment** on the motion for rehearing, and the **<u>deadline for PUC action is June 7, after which the request for rehearing would expire and be deemed denied</u>**. Refer to the RRA article for additional information.

Bottom performers

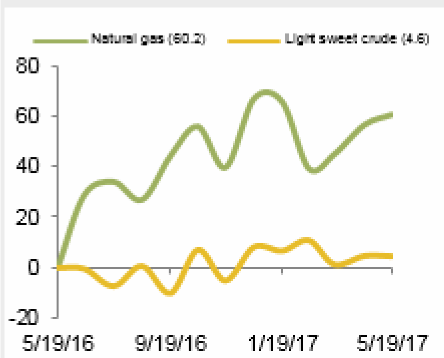
LTM index price change (%)



Price change through 05/19/17 (%)*

	Week	YTD	LTM
Dow Jones Utility	0.2	6.3	8.2
DJIA	-0.3	5.4	19.5
S&P 500	-0.2	6.6	17.0
NASDAQ Composite	-0.3	13.4	29.5

LTM natural gas, oil price prompt month futures price change (%)



Price change through 05/19/17 (%)*

	Week	YTD	LTM
Natural gas	-4.6	-12.3	60.2
Light sweet crude	5.3	-6.2	4.6

*Prices are through midday Friday.
Source: SNL Energy, an offering of S&P Global Market Intelligence

Southwest Gas Holdings Inc. fell 2.7% this week through midday Friday and was the **worst performer in the RRA utility universe for the second consecutive week**. On May 8, the company reported first-quarter 2017 adjusted earnings of $1.45 per share, below the consensus estimate of $1.66 and year-ago EPS of $1.58. Management cited **contractor qualification issues in the company's construction business that halted work,** but did not provide additional detail about the problem.

FirstEnergy Corp. declined 2.2% during the week and was among the worst performing utilities. The Ohio House Public Utilities Committee held its third hearing Tuesday on a bill that was to provide financial support to FirstEnergy's nuclear plants in Ohio. However, it appears there will not be any further action in the House. Without state financial support, FirstEnergy's FirstEnergy Solutions unit may be forced to file for bankruptcy protection.

MGE Energy Inc. slipped 1.8% this week and is down 3.1% year-to-date. However, MGE Energy exhibited strong financial quality for the 12 months ended March 31 for five out of eight metrics included in a recently released analysis. With a capital structure comprised of 65% common equity, MGE Energy had strong pretax and overall fixed charge coverage, as well as return on total capital. For additional detail, see the full report.

The week ahead

We note the following events during the week of May 22-26 that could affect valuations: PJM Interconnection — 2020/2021 Base Residual Auction auction results posted May 23. CenterPoint Energy Resources Corp. (CNP) — Texas gas rate case decision expected from the RRC on May 23. Kentucky Power Co. (AEP) — Rate case filing expected by May 26. Washington Gas Light Co. (WGL) — Hearing examiner's recommendation in Virginia gas rate case could be issued at any time.

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Utilities Stocks Are Back in Favor

by Liying Qian – WSJ – May 16, 2017

Shares of utilities companies are leading gains in the S& P 500 this week, the **latest sign that hopes of stronger economic growth** under President Donald Trump have **moderated**.

The S& P 500's utilities sector posted its seventh consecutive session of gains on Thursday, its longest winning streak in more than a year. The **sector has climbed 2.5% this week, making it the best performer of the index's 11 sectors and outpacing the S& P 500**'s gain of 1.4%.

Investors tend to buy utilities stocks when they are concerned about other parts of the market or are **seeking the sector's relatively hefty dividends in a low-rate environment.** While U.S. economic data point to continued expansion, bond yields have declined, in part reflecting investors' tempered expectations for sharply higher growth and inflation.

The economic data are "showing that rates can come up, but at a slow, gradual pace," said Jay Rhame, portfolio manager at Reaves Asset Management, which specializes in utilities investments. "Nobody's getting worried about inflation rising out of control."

Investors sold utilities and U.S. government bonds after the election, but both have gained this year amid concerns about Mr. Trump's ability to enact tax cuts, deregulation and infrastructure spending. The yield on the 10year Treasury note was 2.254% Thursday, compared with 2.446% at the end of 2016, according to Tradeweb. Yields fall as bond prices rise.

The **utilities sector is up 9.3% in 2017 versus the S& P 500's 7.9% gain**.

Meanwhile, investors are also scooping up technology shares, sending the sector up 20% this year. Tech stocks are prized for their growth potential and have generally offered better-than-average returns since the financial crisis.

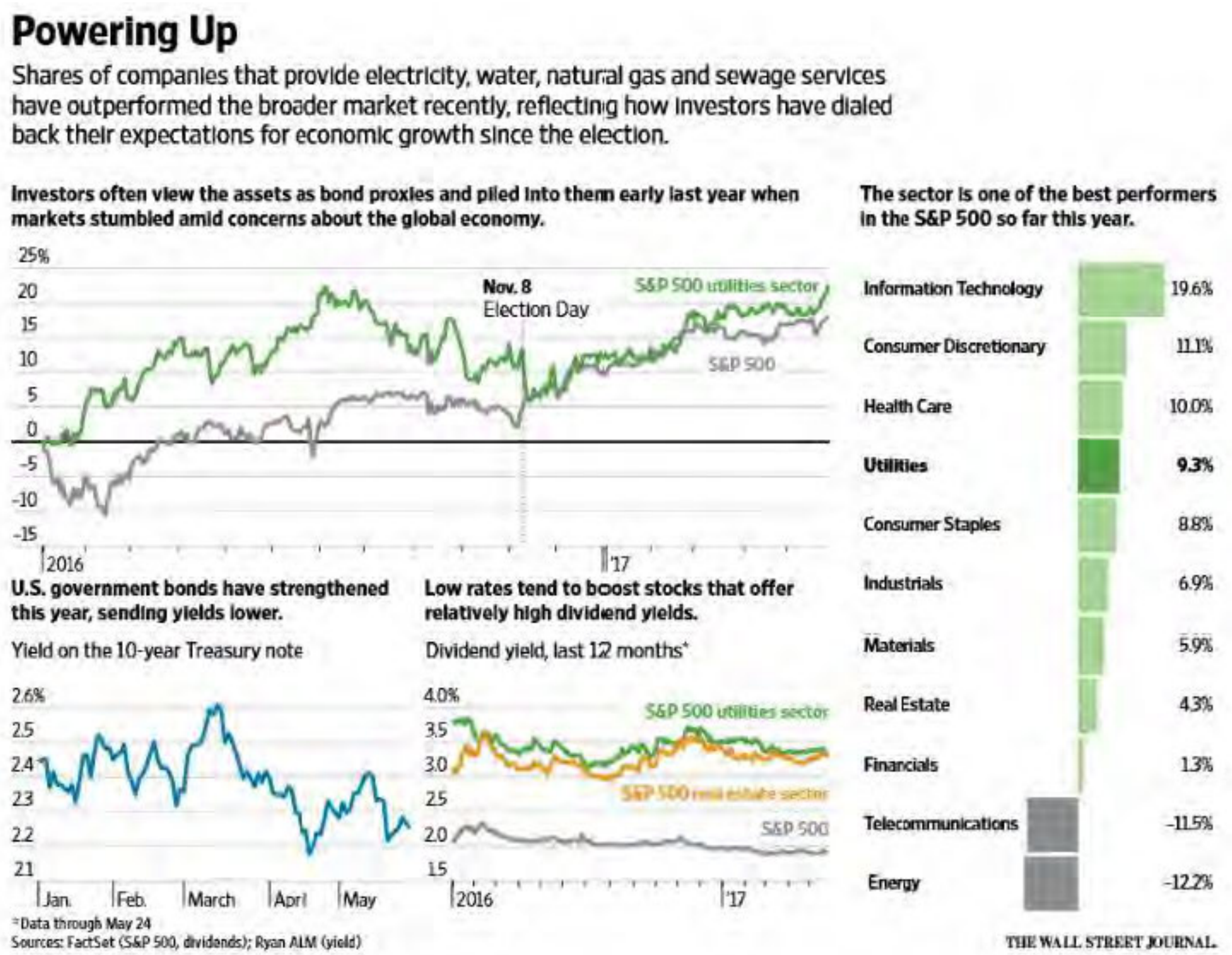
"What's in favor is what I call the barbell," said Russ Koesterich, co-portfolio manager of BlackRock Inc.'s Global Allocation Fund. "At one end you have the safe yield plays, at the other you have the secular growth plays."

Early last year, worries about a global economic slowdown drove investors into utilities stocks, sending the sector up more than 20% in the first half of 2016 and pushing its 12-month trailing price/earnings ratio above the S& P 500's.

The utilities sector got a boost last week as turmoil in Washington cast further doubt on Mr. Trump's ability to push for policy changes.

The relative performance between the Dow Jones Transportation Average and the Dow Jones Utility Average has fallen back near its pre-election level, according to data from Gluskin Sheff & Associates and Haver Analytics, as investors bet less on companies that carry the raw materials and goods powering the economy and more on utilities.

Investors and analysts say **utilities are attractive during broader market turbulence because demand for electricity, water, natural gas and sewage services tends to be stable**. The sector includes shares of companies like DTE Energy Co., a Detroit-based energy company, and Consolidated Edison Inc., which provides electric service to parts of metropolitan New York.



Both companies have gained roughly 11% this year. On Thursday, DTE Energy rose $1.06, or 1%, to $108.98, while Consolidated Edison added 59 cents, or 0.7%, to $82.04.

Some say the recent gains could be fleeting. According to minutes from the Federal Reserve's May meeting released Wednesday, some officials expressed concern about recent softness in inflation, but not enough for them to scrap plans to raise rates two more times this year.

"Overall, the economy's momentum is firm, and the hype around the latest Washington news will dissipate gradually," said Alan Gayle, director of asset allocation at RidgeWorth Investments.

In the long run, Mr. Gayle said he still expects rates to move higher and utilities to retreat.

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Westinghouse's Bankruptcy Filing Will Limit Toshiba's Liabilities

by Masako Kuwahara, VP & Senior Analyst — Moody's — April 3, 2017

Last Wednesday, Toshiba Corporation (Caa1 negative) **announced** that its **majority-owned US nuclear unit Westinghouse Electric Company** LLC (unrated), Westinghouse's **US subsidiaries and affiliates**, **and a holding company for Westinghouse's operating companies outside the US, had filed for Chapter 11 federal bankruptcy protection in New York**. The filing is **credit positive for Toshiba** because it **will limit Toshiba's liabilities**. **However**, **because** the **bankruptcy** filing's financial effect on Toshiba has **not** been **finalized**, **and** the **company's capital structure is poor**, there is a **risk** that **high cash outflows will negatively affect Toshiba's liquidity**.

Toshiba estimates that as of the end of February it had ¥650 billion of parent-company guarantees provided mainly to US power-utility companies, the owners of the four US nuclear reactors currently under construction. We believe this amount will likely be the maximum cash expense that could occur within this fiscal year, ending 31 March 2018. Additionally, Toshiba said that it will provide a maximum of $200 million as a backstop guarantee to Westinghouse group's Chapter 11 financing.

Westinghouse's bankruptcy filing will limit Toshiba's exposure to further losses at the US operations, **but Toshiba's liquidity remains weak** owing to **sizable liabilities and short-term debt**, and the potential acceleration of payment as a result of breach of financial covenants on some of its long-term debt. The planned sale of all, or part, of the company's memory business has the potential to meaningfully bolster liquidity, although the timing and scale of the sale are uncertain.

As a result of the filing, **Westinghouse will be deconsolidated from Toshiba's results** starting in the fiscal year that ended March 2017. Toshiba estimates that the deconsolidation of Westinghouse will boost net income by around ¥200 billion, but the company still expects a net loss of ¥1.01 trillion for the fiscal year that ended March 2017, owing to provisions and losses related to Westinghouse and guarantees provided by Toshiba.

Cost overruns at four of Westinghouse's US nuclear reactors currently under construction have run into the billions. As of December 2016, **total debt accruing to Westinghouse was $9.8 billion, of which $1.3 billion accrued to Toshiba**.

Given Toshiba's speculative-grade rating of Caa1, our analysis focuses on the company's near-term liquidity, its capital position and main bank support. We expect Toshiba's main banks to remain supportive of the company for now as it seeks to maximize the value of its memory business.

Westinghouse Files for Bankruptcy, in Blow to Nuclear Power

by Diane Cardwell and Jonathan Soble – NY Times – Mar. 29, 2017

A Westinghouse project in Waynesboro, Ga., remains unfinished, its future in doubt after the bankruptcy

Westinghouse Electric Company, which helped drive the development of nuclear energy and the electric grid itself, filed for bankruptcy protection on Wednesday, casting a **shadow over the global nuclear industry**.

The filing comes as the company's corporate parent, Toshiba of Japan, scrambles to stanch **huge losses stemming from Westinghouse's troubled nuclear construction projects in the American South**. **Now, the future of those projects**, **which once seemed to be on the leading edge of a renaissance for nuclear energy, is in doubt.**

"This is a fairly big and consequential deal," said Richard Nephew, a senior research scholar at the Center on Global Energy Policy at Columbia University. "You've had some power companies and big utilities run into financial trouble, but this kind of thing hasn't happened."

Westinghouse, a **once-proud name that in years past symbolized America's supremacy in nuclear power, now illustrates its problems**.

Many of the company's injuries are **self-inflicted**, such as a **disastrous deal for** a **construction business** that was **intended to control costs and instead precipitated the events that led to the filing on Wednesday**. Over all, Toshiba has been widely criticized for overpaying for Westinghouse.

But some of what went wrong was beyond either company's control. **Slowing demand for electricity** and **tumbling prices for natural gas** have eroded the economic rationale for nuclear power, which is extremely costly and technically challenging to develop. Alternative-energy sources like wind and solar power are rapidly maturing and coming down in price. The **2011 earthquake in Japan** that led to the nuclear disaster at the **Fukushima** Daiichi plant renewed worries about safety.

Left: Fukushima — Five years after an earthquake and tsunami devastated the northeast Japanese coast, Japan has not fully recovered.

Westinghouse's problems are already reducing Japan's footprint in nuclear power, an industry it has nurtured for decades in the name of energy security. Even before the filing, Toshiba had essentially retired Westinghouse from the business of building nuclear power plants. Executives said they would instead focus on maintaining existing reactors — a more stable and reliably profitable business — and developing reactor designs.

That has **made** the already **small club of companies that take on the giant, expensive and complex task of nuclear-reactor building even smaller**. **General Electric**, a pioneer in the field, has **scaled back** its **nuclear operations**, expressing doubt about their economic viability. **Areva**, the **French builder**, is **mired in losses** and **undergoing** a **large-scale restructuring**.

Among the **winner**s **could be China**, which has ambitions to turn its growing nuclear technical abilities into a major export. That has raised security concerns in some countries.

The shrinking field is a challenge for the future of nuclear power, and for Toshiba's revival plans. Its executives have said they would like to sell all or part of Westinghouse to a competitor, but with a dwindling list of potential buyers — combined with Westinghouse's history of financial calamity — that has become a difficult task.

Toshiba still faces tough questions. The company is also **divesting its profitable semiconductor business and plans to sell a stake to an outside investor to raise capital**. Most of the companies seen as possible buyers are from outside Japan. Some Japanese business leaders have expressed fears that the sale will further erode Japan's place in an industry it once dominated.

After writing down Westinghouse's value, **Toshiba** said it **expected** to **book** a **net loss of $9.9 billion for** its **current fiscal year**, **which ends on Friday**.

"We have all but completely pulled out of the nuclear business overseas," Toshiba's president, Satoshi Tsunakawa, said at a news conference. Of the huge loss, he added, "I feel great responsibility."

Bankruptcy will make it harder for Westinghouse's business partners to collect money they are owed by the nuclear-plant maker. That **mostly affects the**

American power companies for whom it is building reactors, analysts say. Now, it is **unclear whether the company will be able to complete any of its projects, which in the United States are about three years late and billions over budget**.

The power companies — **Scana** Energy in South Carolina and a consortium in Georgia led by **Georgia Power**, a **unit of Southern Company** — would face the **possibility of** new contract terms, long lawsuits and absorbing **losses** that Toshiba and Westinghouse could not cover, analysts say. The cost estimates are already running $1 billion to $1.3 billion higher than originally expected, according to a recent report from Morgan Stanley, and could eventually **exceed $8 billion over all**.

Dennis Pidherny, a **managing director** at **Fitch Ratings** who is **sector head** of the **United States public power group**, said that it was **possible** that the company's **bankruptcy** filing **could terminate the contracts** and that it could be **difficult for the utilities to find another builder to take them over**.

"There's **still quite a bit of work that needs to be completed**," he said. "The biggest challenge there is quite simply finding another suitable contractor who can complete the contract and have it completed at a quote-unquote reasonable cost."

That is, if they are constructed at all. Stan Wise, chairman of the Georgia Public Service Commission, said the utilities developing the Alvin W. **Vogtle** generating station in the **state would have to evaluate whether it made sense to continue**.

"It's a very serious issue for us and for the companies involved," Mr. Wise said. "If, in fact, the company comes back to the commission asking for recertification, and at what cost, clearly the commission evaluates that versus natural gas or renewables."

In a statement on Wednesday, Toshiba said Westinghouse and affiliated companies were "working cooperatively" with the owners to arrange for construction to continue. In recent days, the affected companies issued statements saying they were monitoring the situation and exploring their options, as did the **Energy Department**, which has **authorized $8.3 billion in federal loan guarantees for the Georgia project**.

Toshiba said Westinghouse had total debt of $9.8 billion. The Chapter 11 bankruptcy filing was made in a New York bankruptcy court.

A decade ago, **Toshiba** was dreaming of a big global expansion when it **bought Westinghouse for** a surprisingly high **$5.4 billion and made plans to install 45 new reactors worldwide by 2030**.

At the same time, Westinghouse was trying to install a **novel reactor design**, the **AP1000**. Using simplified structures and safety equipment, it was intended to be easier and less expensive to install, operate and maintain. Its design also **improves** the **ability** to **withstand earthquakes** and **plane crashes** and is **less vulnerable** to a **cutoff of electricity**, **which** is **what set off the triple meltdown at Fukushima**.

Nonetheless, it was inevitable that expansions at the **Vogtle** generating station **in Georgia and** the **Virgil** C. **Summer** plant **in South Carolina** would **hit** some **bumps** along the road to fruition, nuclear executives say. Not only was the **design new**, but, **because nuclear construction** had been **dormant for so long**, **American companies** also **lacked** the **equipment** and **expertise** needed **to make some** of the **biggest components** and **construct** the **projects**.

Indeed, that may ultimately have been at the root of the troubles. The **contractor Westinghouse chose** to complete the projects **struggled to meet** the **strict demands of nuclear construction** and was undergoing its own internal difficulties after a merger. As part of an effort to get the delays and escalating costs under control, Westinghouse **acquired** part of the **construction company**, which **set off** a **series** of still-**unresolved disputes over who should absorb** the **cost overruns** and **how Westinghouse accounted for** and **reported values in** the **transaction.**

White House to Roll Out Trump's First Budget Proposal With Little Fanfare

by Nick Timiraos – WSJ – May 21, 2017

President will be overseas when budget is submitted to Congress, possibly diminishing the attention the event might ordinarily attract

President Donald Trump's first complete budget will be submitted to Congress this week with little fanfare and while Mr. Trump is overseas, an unusual move for the nation's chief executive.

Traditionally, budget submissions follow a series of highly choreographed events designed to provide sustained and broad exposure to an administration's policy agenda.

Workers at Government Publishing Office prepare loose pages of FY2018 budget for binding in Washington, D.C.

Instead, the White House will offer the president's budget proposal on Tuesday while Mr. Trump is in the middle of a nine-day foreign trip to the Middle East and Europe, which could diminish the attention the event might ordinarily attract.

"The fact it's being unveiled in absentia is quite telling in itself," said Stephen Myrow, a former Treasury official in the George W. Bush administration who is now managing partner of research firm Beacon Policy Advisers LLC. It raises a question about how high a priority the budget rates for the president, Mr. Myrow said.

No senior economic officials appeared on the Sunday morning news programs to preview the coming proposals. Top administration officials will testify on the budget on Capitol Hill beginning Wednesday, the same day the Congressional Budget Office is set to release a highly anticipated analysis for the health-care bill approved by House Republicans earlier this month.

While presidential budget proposals are often declared "dead on arrival" because Congress, not the White House, establishes funding levels in annual spending bills, "it's still a big presidential moment to do your budget rollout," Mr. Myrow said.

Officials last week said Mr. Trump's budget will propose large cuts to domestic programs and safety-net spending, such as Medicaid, food assistance and other anti-poverty efforts, to balance the budget over the coming decade without touching the largest drivers of federal spending — Social Security and Medicare. Altogether, the budget will seek to reduce funding by $1.7 trillion over a decade to entitlement programs such as Medicaid and food assistance, whose use swelled after the 2007-09 recession and stood at around 21 million households earlier this year, according to a person familiar with the matter.

The president will also propose increases in military funding, infrastructure and border security.

Few details are expected to be presented on his tax-cut plan, which could add to deficits depending on how it is structured. His advisers say they can sharply boost national output, generating revenue gains that could offset the costs of tax cuts or could hold down deficits without touching the largest entitlement-spending programs.

The types of spending cuts that Mr. Trump may outline, including up to a 40% reduction in nondefense spending compared with current projections over the coming decade, were already mooted by Republican congressional leaders in March, when Mr. Trump offered a preview of the coming budget. That outline called for a nearly 10% boost in defense funding for the fiscal year that begins in October, offset by $54 billion in cuts to foreign aid, environmental, housing, and science and research funding.

The health-care law approved by the House would implement wholesale changes to funding Medicaid that would cut money for the program over time, and Mr. Trump's budget proposal is expected to outline further reductions, according to an administration official familiar with the plans. The Trump proposal could also reduce funding over time for other anti-poverty efforts by capping federal funding to states and introducing work requirements for more beneficiaries.

Funding bills are written by Congress and require 60 votes to clear procedural hurdles in the Senate, which means they need some Democratic support under current rules.

Even if many of Mr. Trump's proposals to cut funding go nowhere in Congress, they could provide Republicans with a balanced-budget blueprint when they turn their attention next month to approving a nonbinding budget resolution. Passing the budget resolution will unlock a key tool allowing Republicans to advance a tax overhaul through the Senate that can't be subject to a filibuster, meaning it would require only 51 votes instead of 60 votes to pass.

Among the more controversial elements of the budget will be the administration's growth forecasts, which assume a large rise in gross domestic product relative to other forecasts but a much smaller pickup in interest rates, which would keep borrowing costs low for the government.

The White House projects the nation's economic growth rate will rise to 3% by 2021, compared with the 1.9% forecast under current policy by the Congressional Budget Office. The **CBO and other forecasters see retiring baby boomer workers and slow worker-productivity growth continuing to restrain output** in the years ahead. But the Trump administration says reductions in taxes and regulations can reverse the trend.

Those growth forecasts will allow the administration to show declining budget deficits that are currently projected to swell due to the costs of caring for an aging population. Under the president's forecast, the national debt would decline as a share of gross domestic product to 60% in 2027 from its current level of 77%. Under current policy, the CBO projects the debt-to-GDP ratio rising to 89%.

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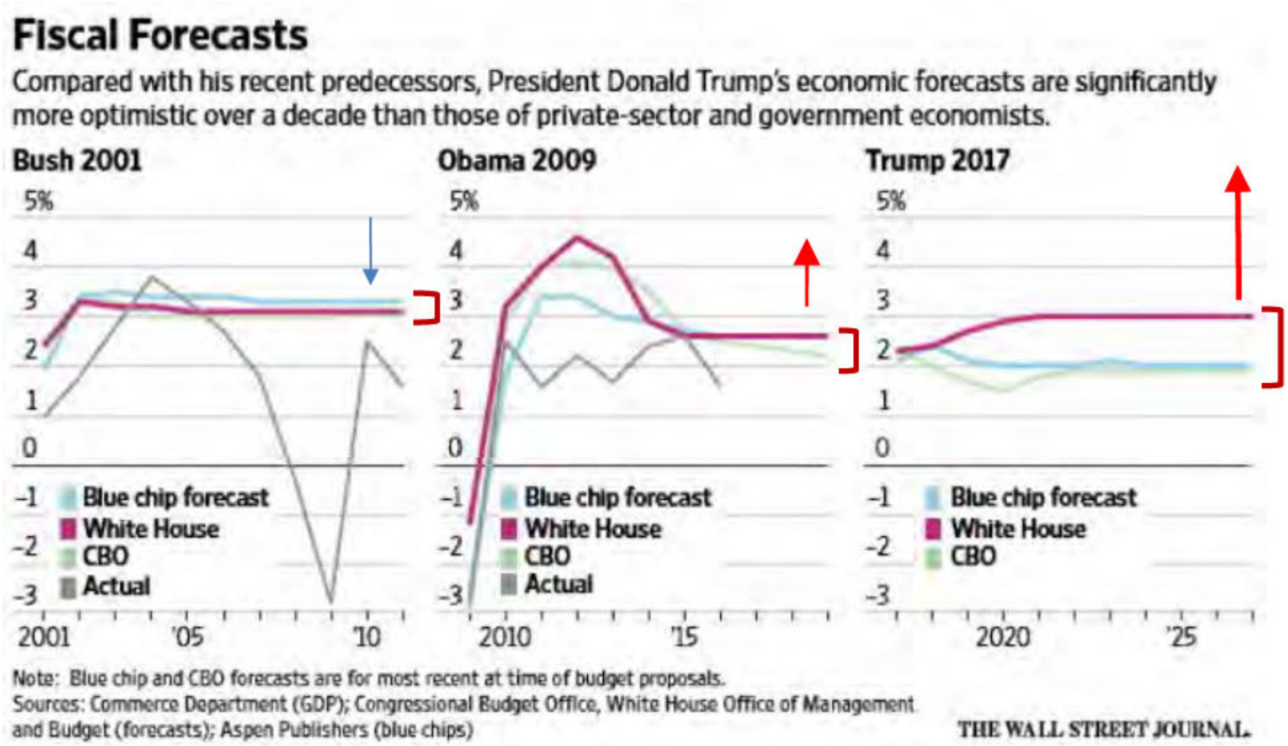
Winners and Losers in the Proposed Budget

WSJ – May 24, 2017



The president's budget proposal serves as a blueprint for his goals and priorities. Here is how some departments would fare:

Defense by Gordon Lubold

The administration is asking for $640 billion in defense spending, more than $50 billion over current congressional budget caps, to pay for modernization, readiness and operations.

One of President Donald Trump's most prominent defense spending proposals during the campaign was to build up the Navy to at least 350 ships from more than 280 in the fleet now. The proposed budget makes small inroads on that score, including funding toward two Virginia-class submarines, two Aegis destroyers and a littoral combat ship

State by Felicia Schwartz

The proposal includes a 32% decrease to the State Department and U.S. Agency for International Development budget to $37.6 billion from $54.9 billion. The budget also includes a 29% cut to foreign assistance, to $25.3 billion.

The U.S. would contribute $5.3 billion in humanitarian assistance funds in 2018 under the proposal, a 31% decrease, though officials said the U.S. would still contribute the most in this area by at least about $2 billion dollars.

The full budget would significantly cut back on contributions to international organizations, which includes the United Nations, international peacekeeping efforts and the World Health Organization and others. Bilateral economic assistance, foreign military financing and global health funding would also face deep cuts.

Interior by Jim Carlton

The proposed $11.7 billion budget for the Department of the Interior raises spending for national parks and oil and gas development, while taking the ax to climate change and other science programs in a plan that has outraged environmental groups.

The spending plan represents an 11% decrease from last year, and if enacted would be the lowest budget for the land and water agency in five years. Hardest hit would be agencies like the U.S. Geological Survey, whose staffing would be slashed by nearly one-fifth.

Education by Tawnell D. Hobbs and Josh Mitchell

A significant cut to college work-study programs and elimination of funding for certain teacher-training and afterschool programs are among $9.2 billion in cuts proposed for the U.S. Department of Education, with some savings being shifted to help fund schoolchoice initiatives. The budget would bolster school choice through about $400 million for expansion of charter schools and vouchers for low-income students to attend private and religious schools.

An additional $1 billion in Title 1 funding, typically targeted for schools with high poverty rates, would be used for a new grant program focused on open enrollment to allow students to attend the public school of their choice.

Justice by Aruna Viswanatha

The Trump administration proposed 300 new federal prosecutors to combat violent crime and prosecute more immigration violations. It also proposed adding $100 million for national security priorities, including 20 new cyber agents at the FBI and 80 positions to specifically help investigators get into encrypted devices.

It also asked for $75 million, including 450 positions to help process a backlog of immigration court cases. That includes 75 new immigration judges. The agency's overall budget is down 3%, which officials attributed to one-time construction cost reductions and money left over from prior years.

Worries Over North Korea Drove Investors into Treasury's Monday April 18, 2018, WSJ

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BPA Cancels I-5 Corridor Reinforcement Project

by Jude Noland – Clearing Up News Bulletin – May 18, 2017

BPA has cancelled its proposed I-5 Corridor Reinforcement Project, a controversial proposal that involved building about 80 miles of new 500-kV transmission line to relieve congestion in BPA's southwest Washington-northwest Oregon service area.

In a Record of Decision issued May 18, BPA Administrator Elliot Mainzer said building the $1.2-billion line "would not fulfill our commitment to making the right investment at the right time."

As a result of a comprehensive review of the project and the inherent difficulties associated with building the line, BPA is taking a new approach to managing grid congestion, Mainzer said.

"My decision reflects a shift for BPA – from the traditional approach of primarily relying on new construction to meet changing transmission needs, to embracing a more flexible, scalable, and economically and operationally efficient approach to managing our transmission system," he said in a three-page letter to parties interested in the project.

"Instead of concentrating all of our energy on one very expensive, concentrated, controversial transmission path, we have a much more robust toolbox and efficient ways to address the challenges in southwest Washington," Mainzer told *Clearing Up.*

A **re-dispatch pilot** scheduled for this summer is expected to provide 115 MW of relief on BPA's congested South of Allston transmission path "will be very revealing," he said.

The coordinated transmission agreement the agency recently signed with the California ISO and the ability to use the Western EIM to manage congestion will also be "very helpful to us."

BPA is also looking at flow-control devices and battery **storage**, he said, along with re-evaluating its commercial products and services to make sure they provide incentives for "efficient utilization of the grid and don't exacerbate congestion problems."

Cost was another issue, he acknowledged. The **current** projected **all-in cost** of the project is **$1.2 billion**, Mainzer told *Clearing Up.* **When first proposed in 2009**, it was expected to cost **$332 million**. BPA's revised approach will save hundreds of millions of dollars over time, Mainzer said.

CASE: UE 319
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 511

PGE March 2017
Investor Presentation

Exhibits in Support
of Opening Testimony

June 16, 2017

Investor Presentation

Portland General Electric
March 2017

Cautionary Statement

Information Current as of February 17, 2017

Except as expressly noted, the information in this presentation is current as of February 17, 2017 — the date on which PGE filed its Annual Report on Form 10-K for the year ended December 31, 2016 — and should not be relied upon as being current as of any subsequent date. PGE undertakes no duty to update the presentation, except as may be required by law.

Forward-Looking Statements

Statements in this news release that relate to future plans, objectives, expectations, performance, events and the like may constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements include statements regarding earnings guidance; statements regarding the expected capital costs for the Carty Generating Station and the recovery of those costs; statements regarding future load, hydro conditions and operating and maintenance costs; statements concerning implementation of the company's integrated resource plan; statements concerning future compliance with regulations limiting emissions from generation facilities and the costs to achieve such compliance; as well as other statements containing words such as "anticipates," "believes," "intends," "estimates," "promises," "expects," "should," "conditioned upon," and similar expressions. Investors are cautioned that any such forward-looking statements are subject to risks and uncertainties, including reductions in demand for electricity; the sale of excess energy during periods of low demand or low wholesale market prices; operational risks relating to the company's generation facilities, including hydro conditions, wind conditions, disruption of fuel supply, and unscheduled plant outages, which may result in unanticipated operating, maintenance and repair costs, as well as replacement power costs; failure to complete capital projects on schedule or within budget, or the abandonment of capital projects, which could result in the company's inability to recover project costs; the costs of compliance with environmental laws and regulations, including those that govern emissions from thermal power plants; changes in weather, hydroelectric and energy markets conditions, which could affect the availability and cost of purchased power and fuel; changes in capital market conditions, which could affect the availability and cost of capital and result in delay or cancellation of capital projects; the outcome of various legal and regulatory proceedings; and general economic and financial market conditions. As a result, actual results may differ materially from those projected in the forward-looking statements. All forward-looking statements included in this news release are based on information available to the company on the date hereof and such statements speak only as of the date hereof. The company assumes no obligation to update any such forward-looking statement. Prospective investors should also review the risks and uncertainties listed in the company's most recent annual report on form 10-K and the company's reports on forms 8-K and 10-Q filed with the United States Securities and Exchange Commission, including management's discussion and analysis of financial condition and results of operations and the risks described therein from time to time.

PGE Value Drivers

- Clear focus: 100% regulated utility
- Attractive service area
- Progressive environmental and renewable position
- Focus on operational effectiveness and efficiency
- Strong financial position
- Generation, T&D and IT resiliency initiatives strengthen infrastructure

The Company

Strong Platform for Stakeholder Value

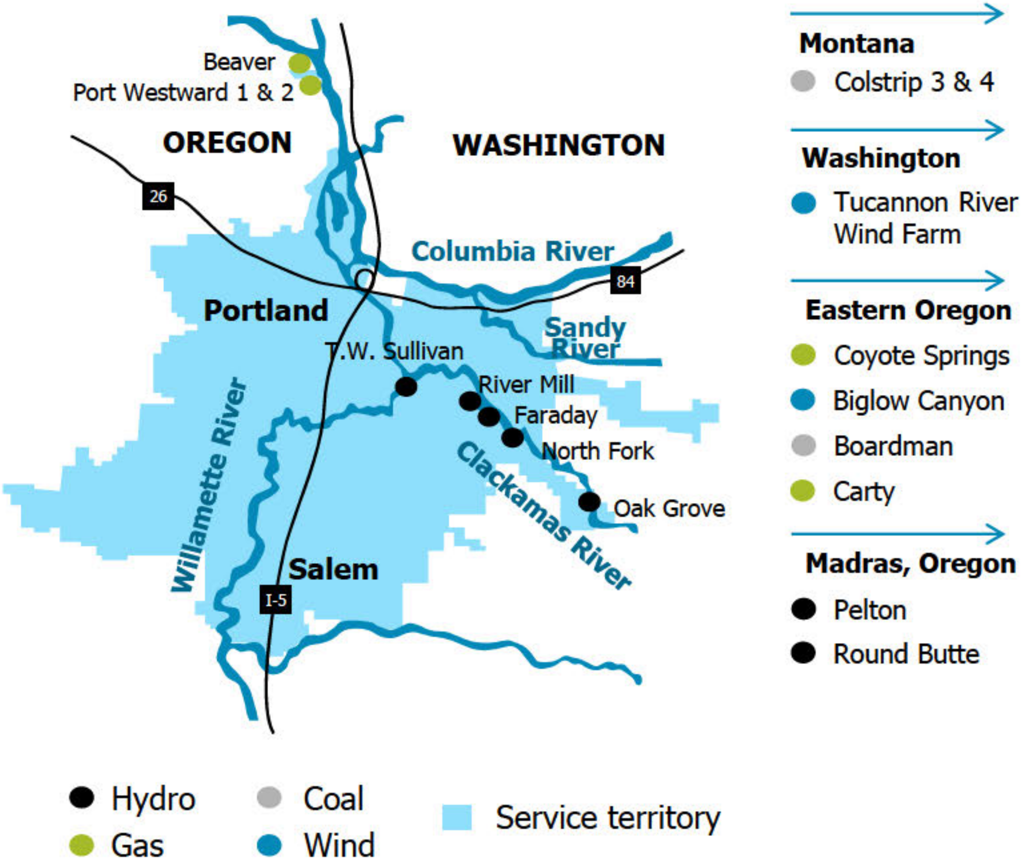
PGE at a Glance

Quick Facts:

- Vertically integrated energy company encompassing generation, transmission and distribution
- ~863,000 customers[(1)]
- 46 percent of Oregonians, 51 incorporated cities
- Service area covers majority of Oregon's commercial and industrial activity

Financial Snapshot[(1)]:

- Revenue: $1.9 billion
- Earnings per share: $2.16
- Net Utility Plant Assets: $6.4 billion



(1) As of 12/31/2016

Strategic Direction

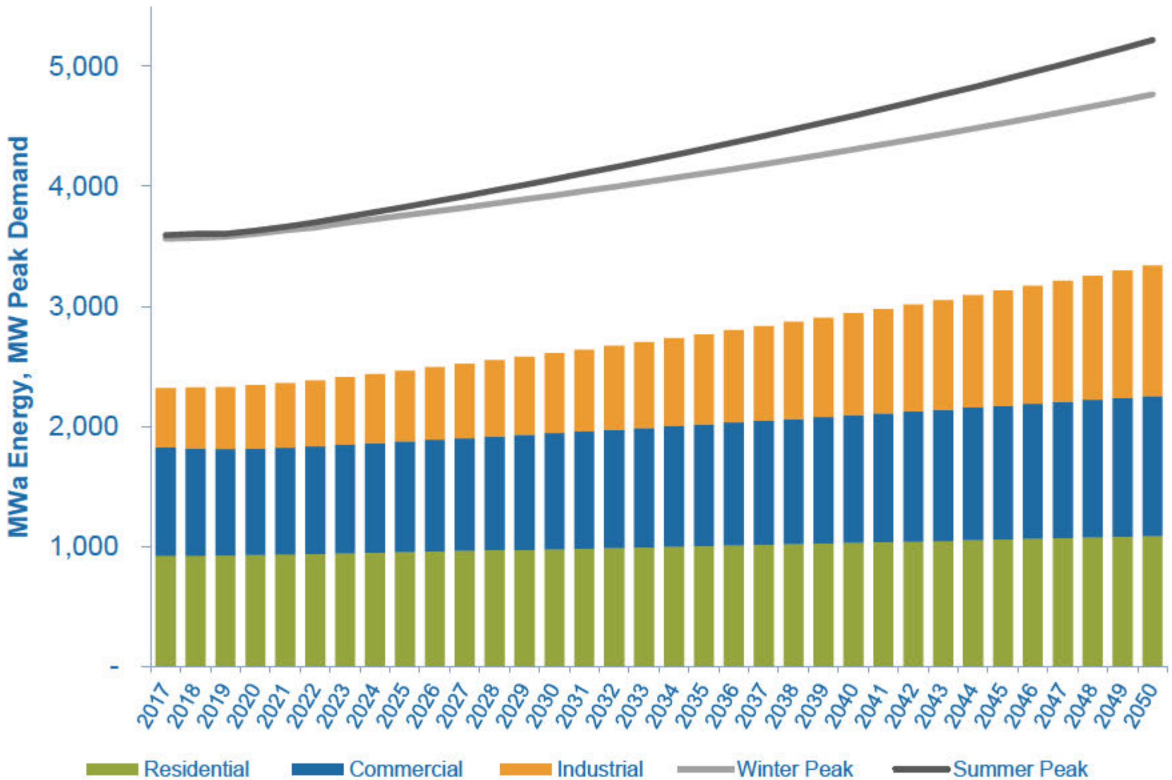
Mission: To be a company our customers and communities can depend upon to provide electric service in a safe, sustainable and reliable manner, with excellent customer service, at a reasonable price.

The path forward is guided by:

- Strong relationships with customers and community
- Empowering employees
- Opportunity to grow the business
- Delivering value to all stakeholders

Attractive, Growing Service Area

Long-Term Load Growth



- Long-term forecast ~1% annually through 2050
- Driven by:
  - Industrial deliveries growth
  - Residential customer growth
  - Energy efficiency

Constructive Regulatory Environment

Regulatory Construct

- Oregon Public Utility Commission
- 9.6% allowed return on equity
- 50% debt and 50% equity capital structure
- Forward test year
- Integrated Resource Planning (IRP)
- Renewable Portfolio Standard (RPS)

Governor-appointed three-member commission

Chair:	Lisa Hardie [D][1]	May 2020
	Megan Decker [D][2]	Mar 2021
	Stephen Bloom [R]	Nov 2019

Regulatory Mechanisms

- Net variable power cost recovery
  - Annual Power Cost Update Tariff (AUT)
  - Power Cost Adjustment Mechanism (PCAM)
- Decoupling through 2019
- Renewable Adjustment Clause

(1) Newly appointed at the end of May 2016
(2) Newly appointed, replacing outgoing commissioner John Savage.

2018 General Rate Case

Seeking Approval from the Oregon Public Utility Commission

For investments in the system to keep it safe, reliable and secure

- Filed Feb. 28, 2017
- 2018 Forward Test Year
- Expected Commission order by Dec. 2017
- Customer Prices will be effective Jan. 1, 2018

- Return on Equity: 9.75%
- Rate Base: $4.6 billion
- Capital Structure: 50% debt, 50% equity
- Cost of Capital: 7.46%
- Annual revenue requirement increase: $100 million
- Overall increase in customer prices: 5.6%

The Strengths

Strong Platform for Stakeholder Value

Key Strengths

1. Our focus on customers
2. Diverse generation and customer base
3. High quality utility operations
4. Solid financial performance
5. Strong financial position

Focus on customers

Top Quartile System Reliability
Edison Electric Institute

Top Quartile Customer Satisfaction
TQS Research, Inc.

Most Trusted Brand & No. 1 for Dedication to the Environment
Market Strategies International

Top Ranked Renewable Energy Program
National Renewables Energy Laboratory

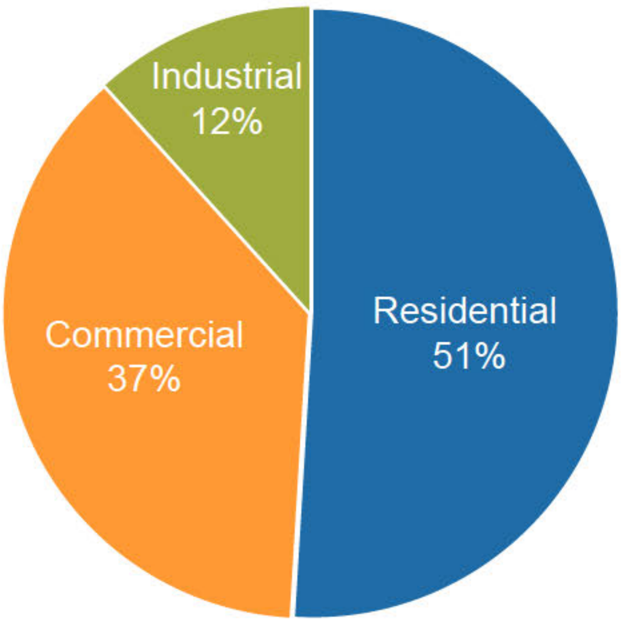
All customer satisfaction and reliability measures consistently top quartile

Diverse Generation & Customer Base

Retail Revenues by Customer Class

(2016)

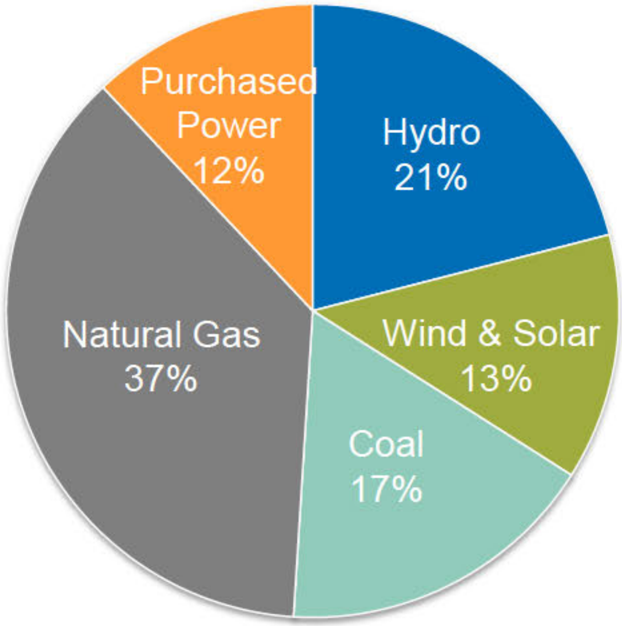
Total = $1.78B



Power Sources as a Percent of Retail Load

(2016 AUT)[1]

Total = 2,120 MWa



(1) Hydro and wind/solar include PGE owned and contracted resources; purchased power includes long-term contracts

High Quality Utility Operations

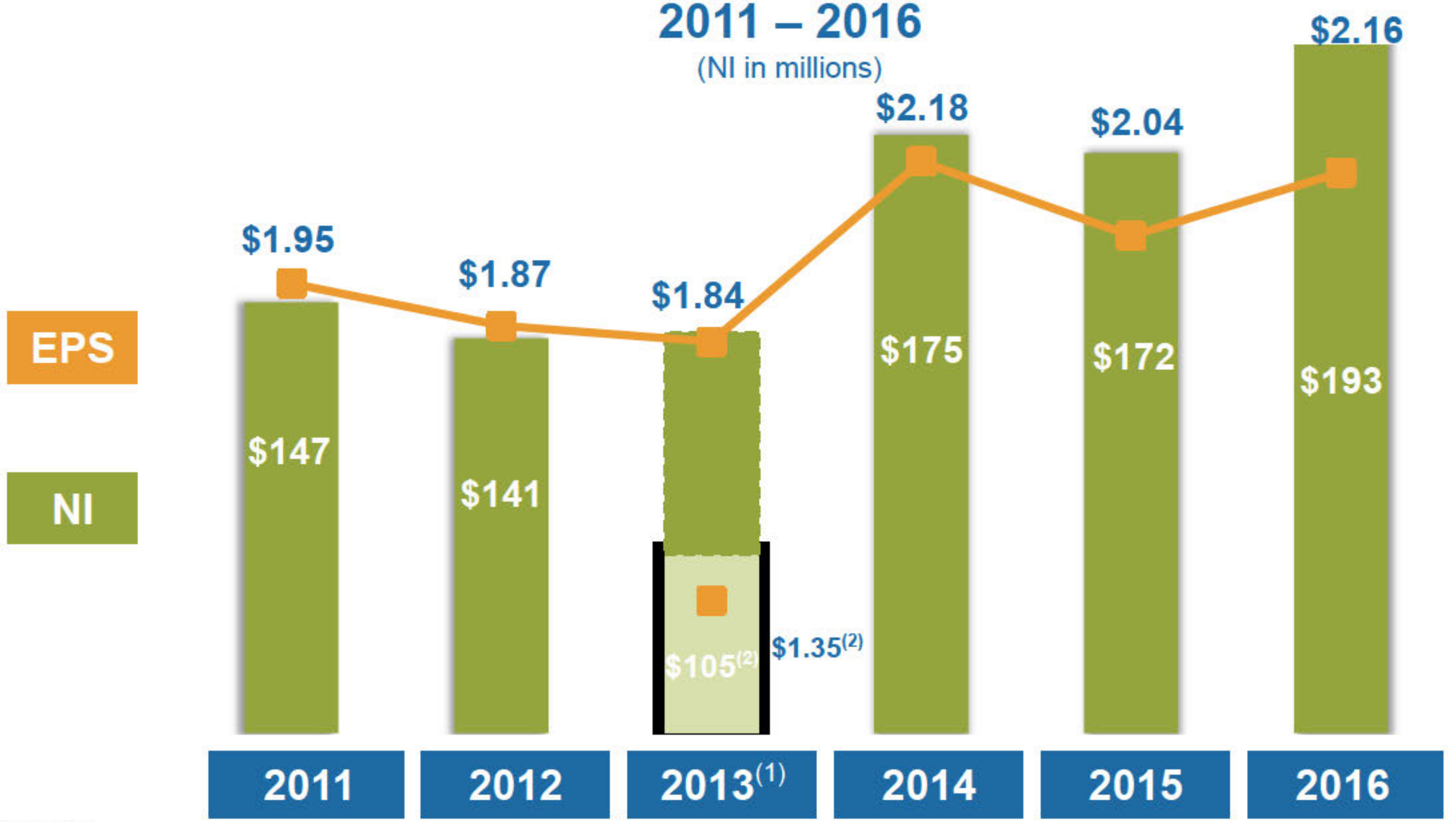
- Highly dependable PGE generation portfolio with five-year average availability of 92 percent[1]
- Strong power supply operations to stabilize and optimize power costs
- Progressive approach to reduce coal generation – Boardman 2020 Plan and Colstrip 2035 Plan
- Generation, T&D and IT initiative focused on improving efficiency, reliability and resiliency to meet customer needs and expectations
- Ongoing investment in technology to improve service and capture efficiencies

(1) Represents 2012 through 2016

Solid Financial Performance

Net Income, Earnings per Share, and ROE 2011 – 2016

(NI in millions)

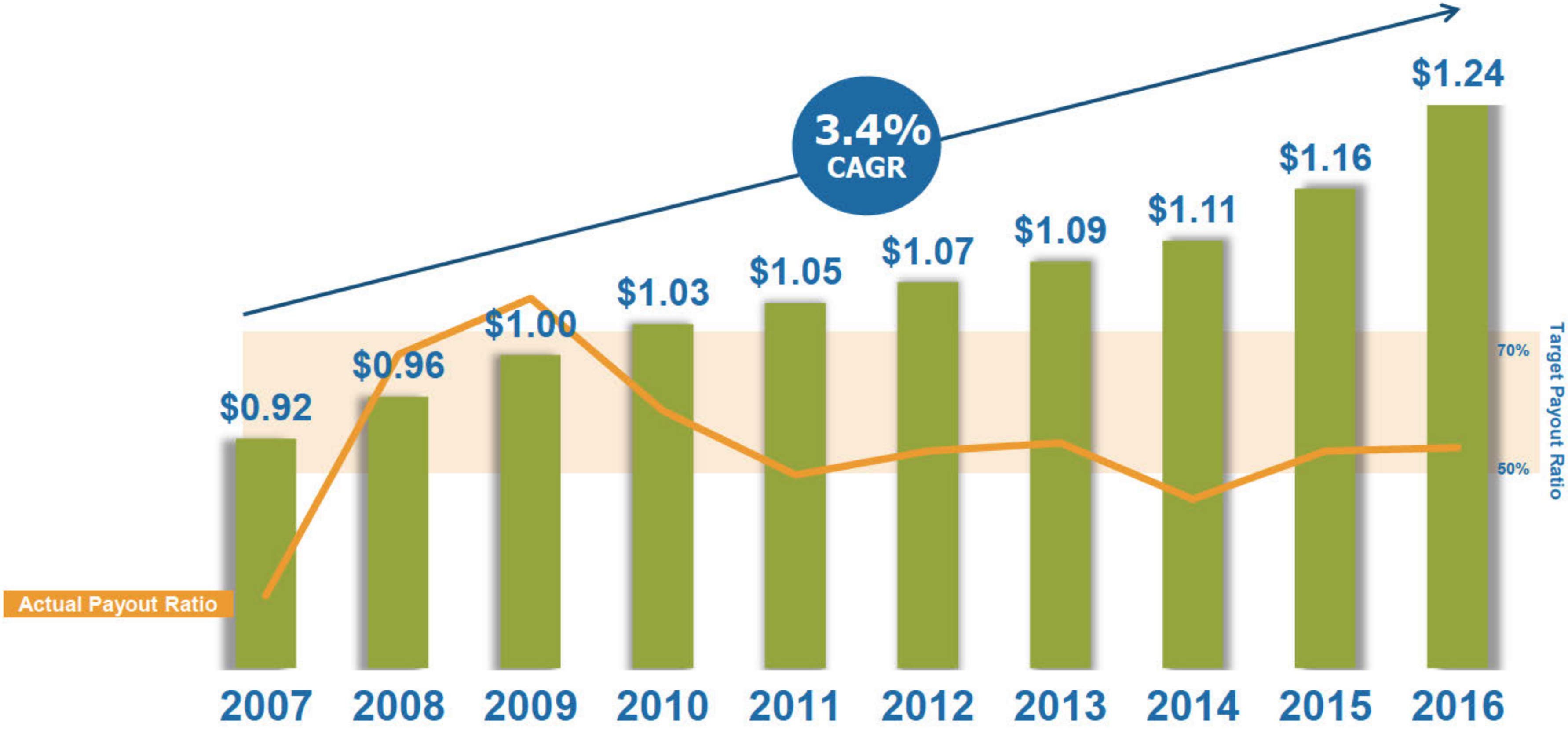


	2011	2012	2013(1)	2014	2015	2016
ROE	9.0%	8.3%	7.9%	9.4%	8.3%	8.4%
Allowed ROE	10.0%	10.0%	10.0%	9.75%	9.68%	9.6%

(1) 2013 displays full-year non-GAAP adjusted operating earnings, which excludes the negative impact of the Cascade Crossing expense ($0.42 EPS) and the customer billing refund ($0.07 EPS)

(2) GAAP earnings for year-end 2013 were $105 million or $1.35 per diluted share

Consistent Dividend Growth

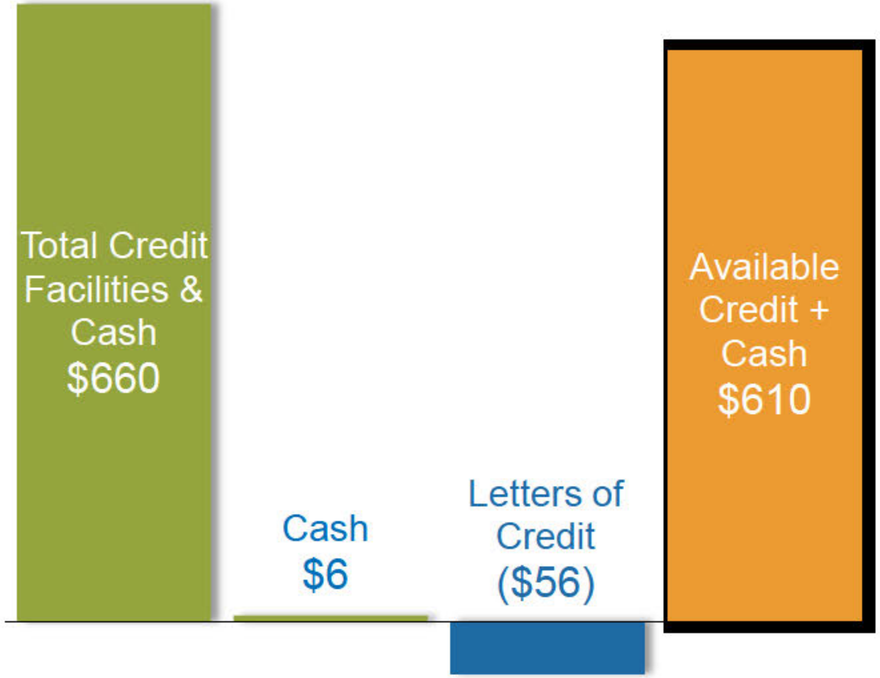


Annual dividend increases expected to be in the 5-7% range[1]

Note: Represents annual dividends paid
(1) Based on the company achieving earnings and cash flow estimates and other factors influencing dividends and subject to approval of the Board of Directors

Strong Liquidity Position for Growth

Revolving Credit Facilities [1]
(in millions)



(1) All values as of 12/31/2016

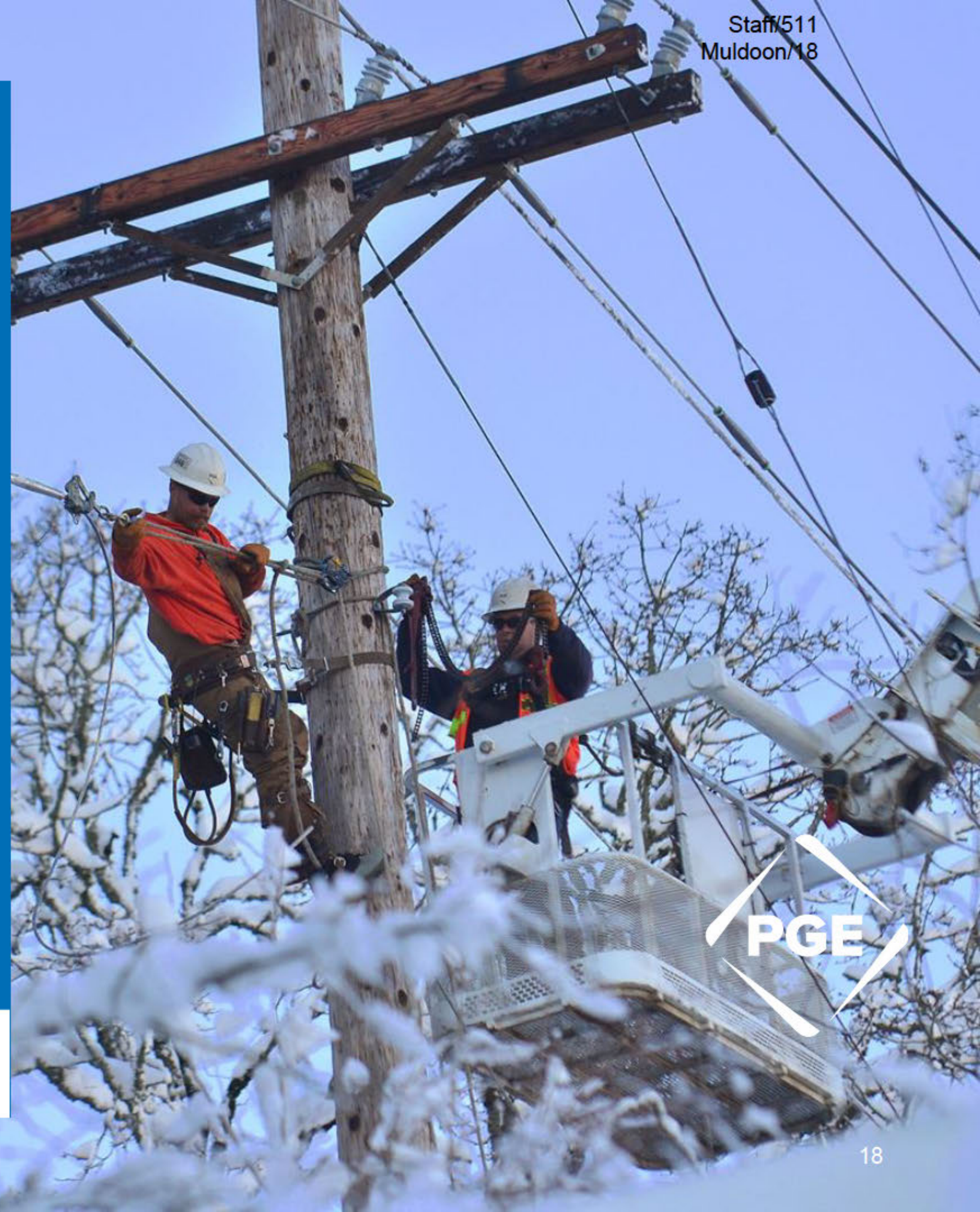
Financial Resources

- Investment grade credit ratings
- Manageable debt maturities
- Target capital structure of 50% debt and 50% equity

	S&P	Moody's
Senior Secured	A-	A1
Senior Unsecured	BBB	A3
Outlook	Stable	Stable

The Execution

Strong Platform for Stakeholder Value



New Generation: Baseload Resource

Carty Generating Station: Placed in-service on July 29, 2016

Carty Generating Station, a 440 MW natural gas baseload plant near Boardman, OR

Capital costs, including AFDC, approved in 2016 GRC:	$514M
Total estimated cost, including AFDC, for completion:	$640M[(1)]
Carty plant in-service as of 12/31/2016:	$634M
Estimated time frame to complete litigation:	2-4 years

(1) Total estimated cost does not reflect any amounts that may be received from sureties under the performance bond, the original contractor, or contractor's parent company

2016 Integrated Resource Plan

Nov. 2016	Q3 2017	2nd Half 2017	2018
IRP was filed	OPUC acknowledgement expected	RFP bidding process commences	Expected to reach decision on RFPs

- Reflects PGE's shift to more renewables in keeping with Oregon Clean Electricity Plan
- Process includes continuing dialog with OPUC staff and stakeholders
- RFPs will be open to a variety of resource options

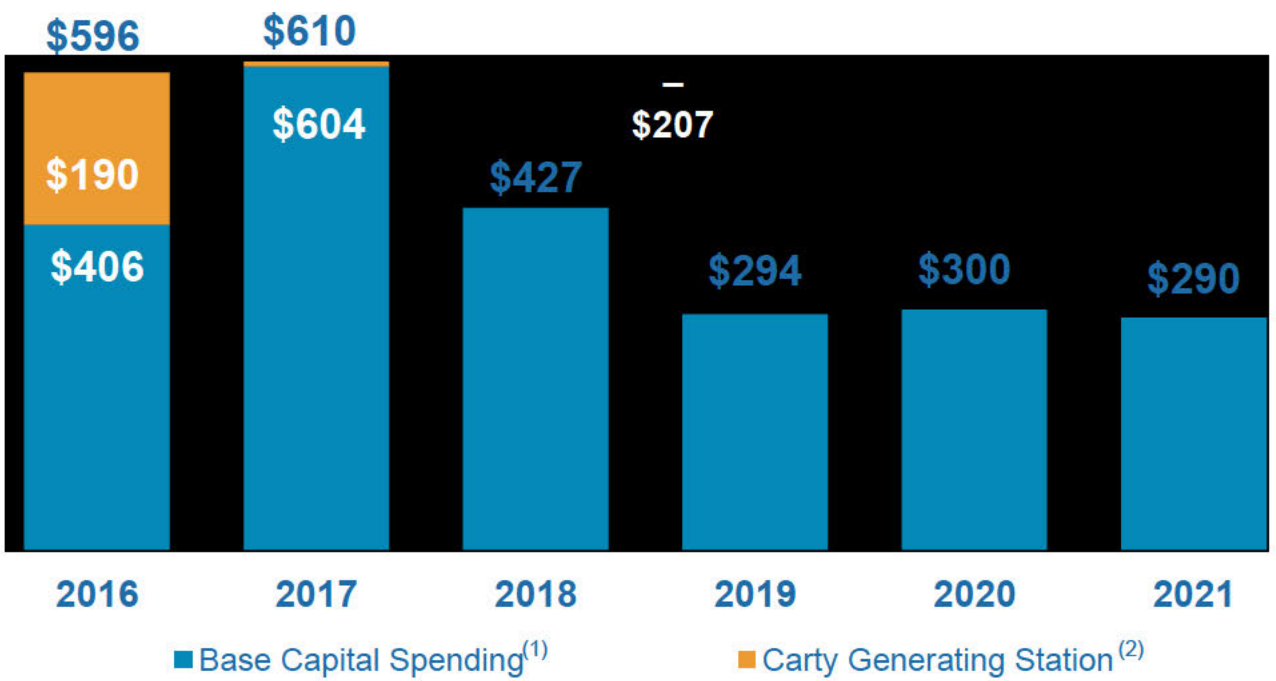
Areas of Focus

- Energy efficiency (135 MWa) and demand-side actions (77 MW)
- Investment / acquisition of renewables (175 MWa) to meet Oregon Clean Electricity Plan: IRP will position PGE to comply with 27% RPS requirement by 2025
- Filling up to 700 MW capacity deficit to ensure reliability[1]

[1] On March 31, 2017, PGE executed a 10-year PPA with Douglas County Public Utility District for a share of the output of the Wells Hydroelectric project. Based on average hydro conditions and projected load growth, PGE anticipates approximately 130-160 MW of capacity and 60-70 MWa of energy, beginning Sept. 1st, 2018. PGE is currently evaluating the impact of this PPA on the remaining 2021 capacity shortage and will provide an update when practicable.

Forecasted Capital Expenditures

$ millions



Outlook

Annually the board of directors will review the need for additional investments focused on improving the efficiency, reliability and resiliency of PGE's infrastructure to meet customer needs.

Capital additions that could result from the Request For Proposal following acknowledgment of the Integrated Resource Plan have not been estimated and are not shown.

Note: Amounts do not include AFDC

(1) Consists of board-approved ongoing Cap Ex per the Form 10-K filed on February 17, 2017

(2) Total estimated cost does not reflect any amounts that may be received from sureties under the performance bond, the original contractor, or contractor's parent company

PGE Value Proposition

Strong platform executing sustained long-term growth

- High quality utility operations
- Attractive service territory
- Strong financial position
- Generation and T&D resiliency initiatives
- Progressive reduction in carbon footprint & intensity
- Future infrastructure investment opportunities

PGE Investor Relations Team

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Portland General Electric

Appendices

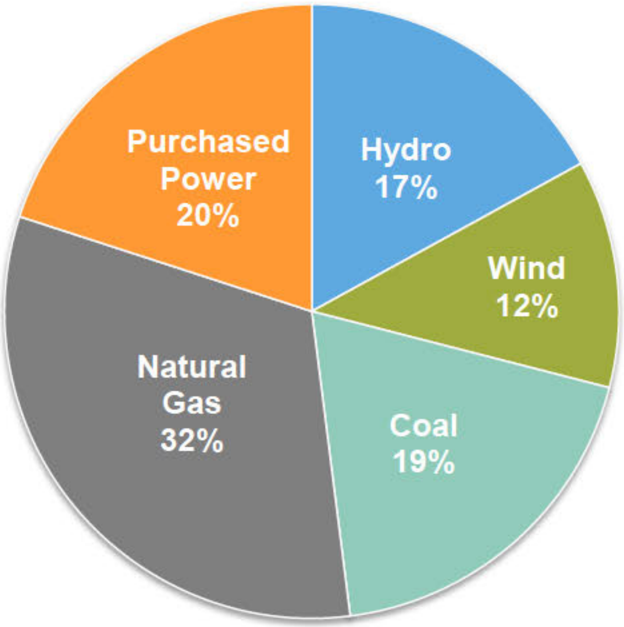
Diversified Resource Mix

Resource Capacity
as of 12/31/2016

	Capacity in MW	% of Total Capacity
Hydro[1]		
Deschutes River Projects	303	6%
Clackamas/Willamette River Projects	192	4%
Hydro Contracts	534	11%
	1,029	**22%**
Natural Gas/Oil[1]		
Beaver Units 1-8	508	11%
Coyote Springs	243	5%
Port Westward Unit 1	395	8%
Port Westward Unit 2	225	5%
Carty	434	9%
	1,805	**38%**
Coal[1]		
Boardman	518	11%
Colstrip	296	6%
	814	**17%**
Wind		
Biglow Canyon[2]	450	10%
Tucannon River[3]	267	6%
Wind and Solar Contracts	52	1%
	769	**17%**
Additional Purchased Power	**313**	**7%**
Total	**4,730**	**100%**

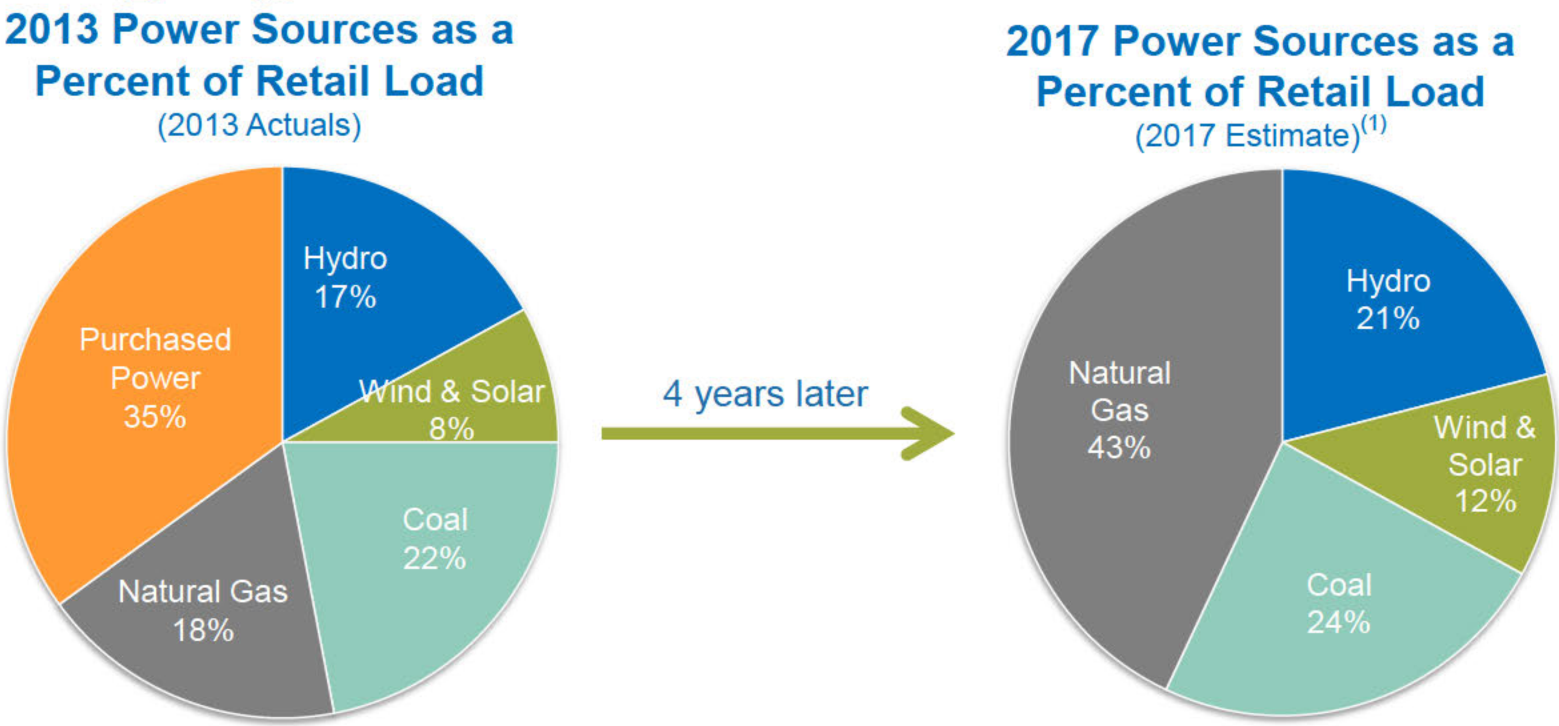
Power Sources as a Percent of Retail Load
(2016 Actuals)

Total = 18,295,000 MWh



(1) Capacity of a given plant represents the megawatts the plant is capable of generating under normal operating conditions, net of electricity used in the operation of the plant.
(2) With respect to Biglow Canyon, capacity represents nameplate and differs from expected energy to be generated, which was a 23% capacity factor in 2016.
(3) With respect to Tucannon River Wind Farm, capacity represents nameplate and differs from expected energy to be generated, which was a 28% capacity factor in 2016.

Changing Generation Portfolio



Changes driven by:

- New generation: Port Westward Unit 2 (natural gas, Q4 2014), Tucannon River (wind, Q4 2014), and Carty (natural gas, July 2016)
- Next requirements under Oregon's RPS (requiring a portion of PGE's retail load to be serviced by renewable resources): 20% by 2020, 27% by 2025, 35% by 2030, 45% by 2035 and 50% by 2040

Note: For both charts, hydro and wind/solar include PGE owned and contracted resources
(1) Based on an estimated forecast which includes new generation from Carty

Financing Activity

Equity Issuances

	Date	Shares	Net Proceeds
Equity Forward Sale Agreement	June 2013	11.1 million	--
Draw pursuant to forward	August 2013	0.7 million	$20 million
Draw pursuant to forward	June 2015	10.4 million	$271 million
Net remaining shares available for issuance:		0	
Equity Over-Allotment	June 2013	1.7 million	$46 million

Long-term Debt ($ in millions)

Issued:

Amount	Issuance Date	Coupon	Maturity
$100	8/15/14	4.39%	2045
$100	10/15/14	4.44%	2046
$80	11/17/14	3.51%	2024
$75	1/15/15	3.55%	2030
$70	5/19/15	3.50%	2035
$140	1/6/16	2.51%	2021
$50	5/4/16	~1.4%	Nov 2017
$75	6/15/16	~1.4%	Nov 2017
$25	10/31/16	~1.4%	Nov 2017

Matured/Redeemed:

Amount	Date
$70	Matured – Jan 2015
$67	Redeemed – May 2015
$75	Redeemed – Jan 2016
$58	Redeemed – Jan 2016

Generation Plant Operations

- **Track record of high availability**

	2011	2012	2013	2014	2015	2016
PGE Thermal Plants	90%	92%	84%	89%	89%	92%
PGE Hydro Plants	100%	99%	100%	100%	99%	99%
PGE Wind Farm	97%	98%	98%	94%	97%	95%
PGE Wtd. Average	**93%**	**94%**	**89%**	**92%**	**93%**	**93%**
Colstrip Unit 3 & 4	84%	93%	66%	83%	93%	85%

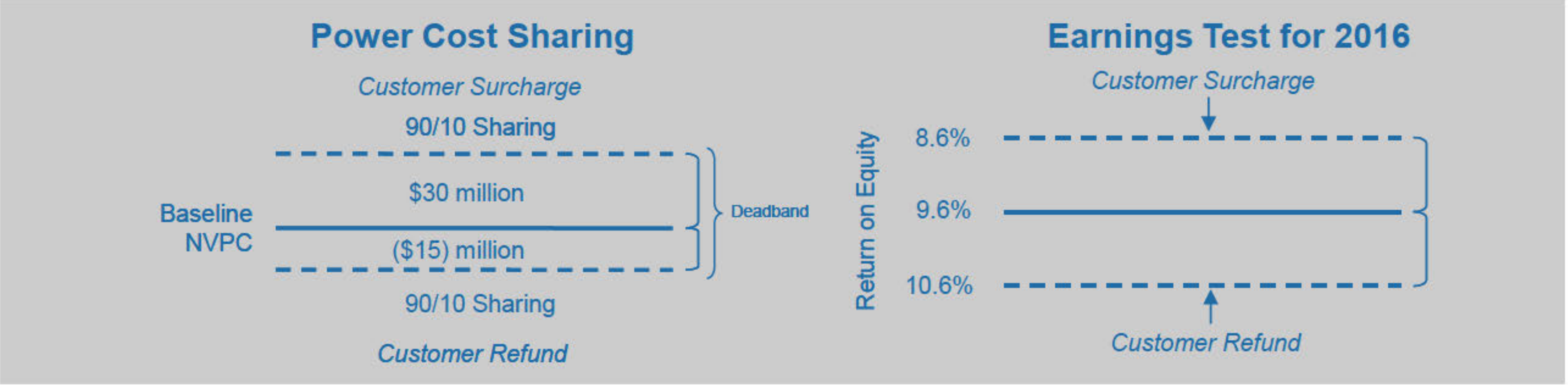
- **Generation Reliability and Maintenance Excellence Program**
  - Corporate strategy started in 2007 to increase availability of PGE's generation plants and increase predictability of plant dispatch costs for power operations
  - Key Elements
    - Reliability Centered Maintenance (RCM) modeling for PGE's generating plants and incorporation of models into PGE's maintenance management system (Maximo)
    - Root Cause Analysis (RCA) for unplanned generation outages, which expedites communication across PGE's fleet on both resolution and prevention actions
    - Internal training on technical skills, including inspection, welding and metallurgy – supporting both RCM and RCA efforts

Recovery of Power Costs

Annual Power Cost Update Tariff

- Annual reset of prices based on forecast of net variable power costs (NVPC) for the coming year
- Subject to OPUC prudency review and approval, new prices go into effect on or around January 1 of the following year

Power Cost Adjustment Mechanism (PCAM)



- PGE absorbs 100% of the costs/benefits within the deadband, and amounts outside the deadband are shared 90% with customers and 10% with PGE
- An annual earnings test is applied, using the regulated ROE as a threshold
- Customer surcharge occurs to the extent it results in PGE's actual regulated ROE being no greater than 8.6%; customer refund occurs to the extent it results in PGE's actual regulated ROE being no less than 10.6%

2018 General Rate Case - Key Dates

Date	Event
April 7th	Deadline to file petitions to Intervene
May 5th	Staff Workshop
June 16th	Staff and Intervenors file opening testimony
July 18th	PGE files Reply Testimony
August 3rd - 4th	Settlement Conferences
August 17th	Staff and Intervenors file Cross-Answering and Rebuttal Testimony
September 5th	PGE files Surrebuttal Testimony
September 12th	All Parties file Joint Issues List, Cross-examination settlement, and Exhibit lists
October 24th (tentative)	Oral arguments
December 21st	Target date for Commission Order
January 1st, 2018	Effective Date

2016 General Rate Case

Oregon Public Utility Commission Order

- Overall increase in customer prices: 0%
- Return on Equity: 9.6%
- Capital Structure: 50% debt, 50% equity
- Cost of Capital: 7.51%
- Rate Base: $4.4 billion(1)
- Annual revenue requirement increase: $12 million

Customer Prices

- Base Business: January 1, 2016
- Carty: August 1, 2016

Customer price changes:

  - Base business reduction of 2.5%
  - Carty increase of 2.5%

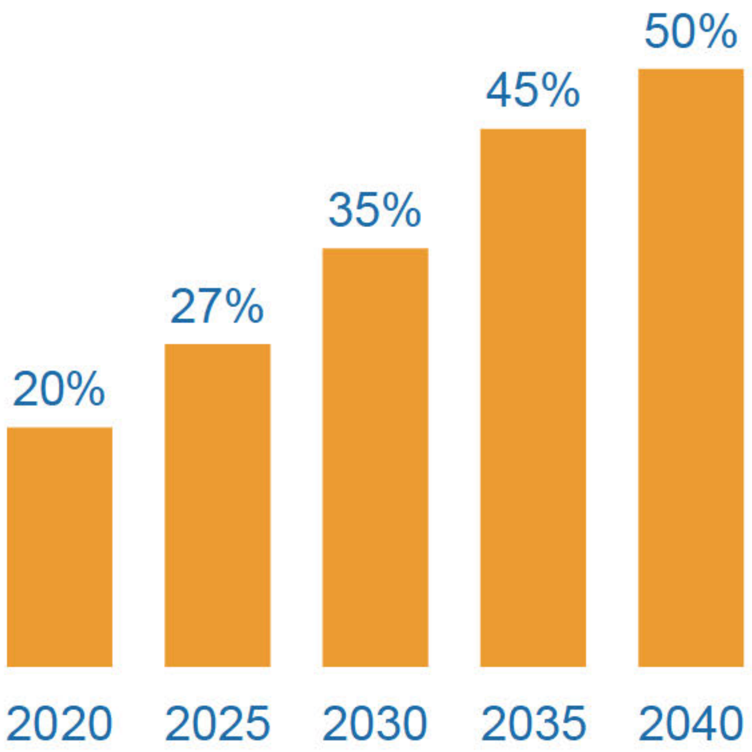
(1) Includes Carty at $514 million

Oregon Clean Electricity Plan

Oregon Senate Bill 1547

Key Elements of Plan

- Increase the renewable portfolio standard to 50 percent in 2040
- Transitions Oregon off coal-fired generation by 2035
- Includes PTCs in power costs, beginning with AUT filing for 2017
- Reaffirms state's commitment to energy-efficiency programs
- Encourages transportation electrification
- Increases access to solar energy for more Oregonians
- Flexibility to achieve goals while working with the Oregon Public Utility Commission



New renewable portfolio standards

Renewable Portfolio Standard

Additional Renewable Resources

- PGE's 2009 Integrated Resource Plan addressed procurement of renewable resources to meet the 2015 requirement of Oregon's Renewable Portfolio Standard (RPS). As of 2016, PGE had the following qualifying renewable resources:

Type of Resource	% of Retail Load
Wind	11.6%
Low Impact Hydro	3%
Solar & Other	0.3%

Renewable Portfolio Standard:

2011	2015	2020	2025	2030	2035	2040
5%	15%	20%	27%	35%	45%	50%

- Renewable Portfolio Standard qualifying resources supplied approximately 10 percent of PGE's retail load in 2012, 2013, & 2014, and approximately 15 percent of retail load in 2015 and 2016.

Renewable Adjustment Clause (RAC)

- Renewable resources can be tracked into prices, through an automatic adjustment clause, without a general rate case. A filing must be made to the OPUC by the sooner of the online date or April 1 in order to be included in prices the following Jan. 1. Costs are deferred from the online date until inclusion in prices and are then recovered through an amortization methodology.

Executing on New Generation

Tucannon River Wind Farm

Capacity: 267 MW

In-service date: Dec. 2014

Project cost: $525 M

On time
On budget

Port Westward Unit 2

Capacity: 220 MW

Fuel: Natural Gas
Reciprocating Engines

In-service date: Dec. 2014

Project cost: $311 M

Decoupling Mechanism

The decoupling mechanism is intended to allow recovery of margin lost due to a reduction in sales of electricity resulting from customers' energy efficiency and conservation efforts.

This includes a Sales Normalization Adjustment (SNA) mechanism for residential and small nonresidential customers (≤ 30 kW) and a Lost Revenue Recovery Adjustment (LRRA), for large nonresidential customers (between 31 kW and 1 MWa).

- The SNA is based on the difference between actual, weather-adjusted usage per customer and that projected in PGE's 2016 general rate case. The SNA mechanism applies to approximately 61% of 2016 base revenues.
- The LRRA is based on the difference between actual energy-efficiency savings (as reported by the ETO) and those incorporated in the applicable load forecast. The LRRA mechanism applies to approximately 27% of 2016 base revenues.

In PGE's 2016 rate case, PGE and parties stipulated to the extension of the decoupling mechanism for three years, through the end of 2019. In addition, the use-per-customer baseline was adjusted for new connects with lower energy usage.

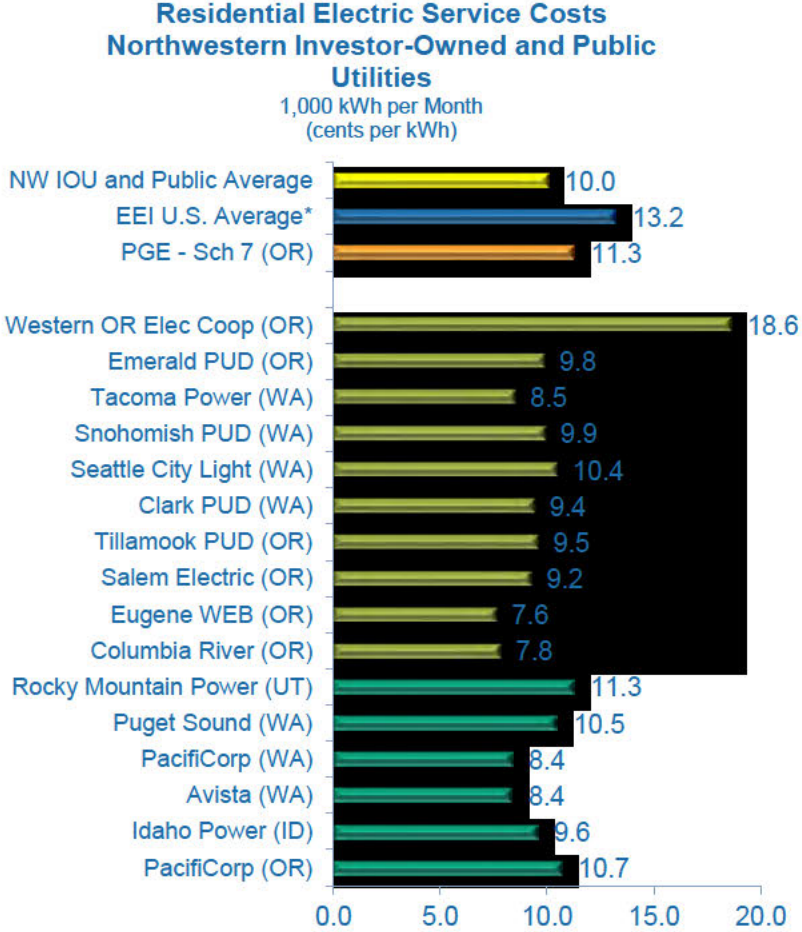
Recent Decoupling Results

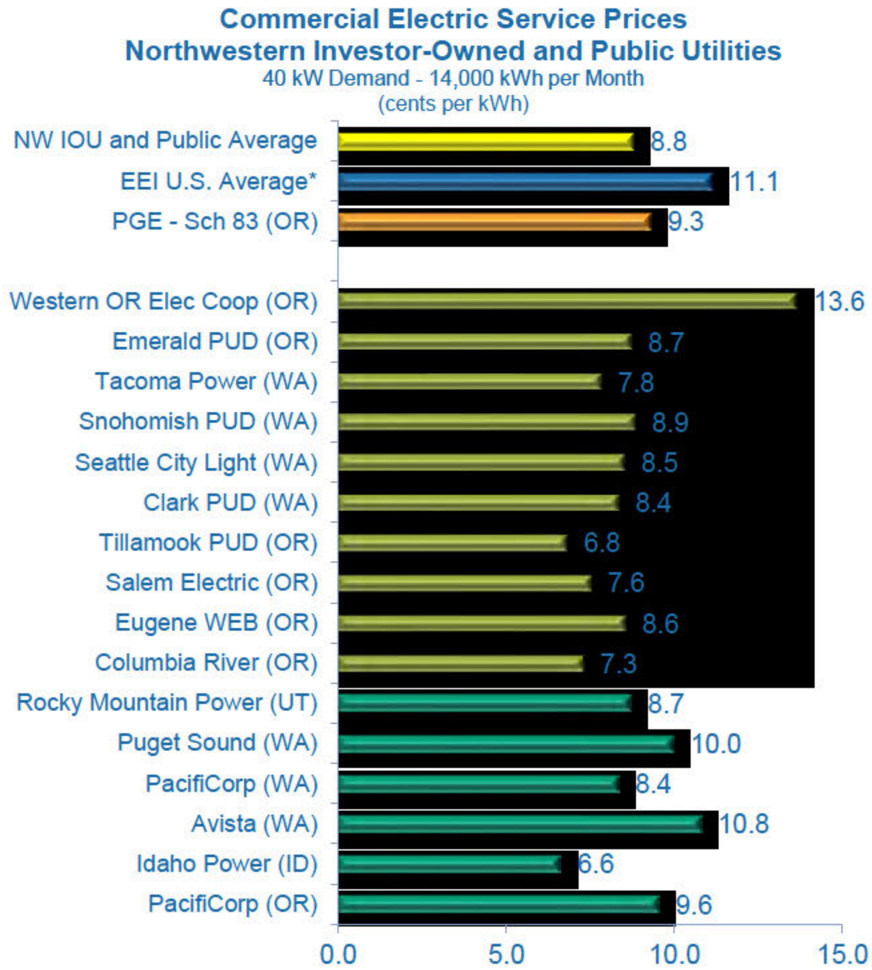
(in millions)	**2014**	**2015**	**2016**
Sales Normalization Adjustment	$(6.6)	$(8.8)	$1.9
Lost Revenue Recovery Adjustment	$1.4	$(0.5)	$(0.8)
Total adjustment	**$(5.2)**	**$(9.3)**	**$1.1**

Note: refund = (negative) / collection = positive

Average Retail Price Comparison

Residential and Commercial – Winter 2016

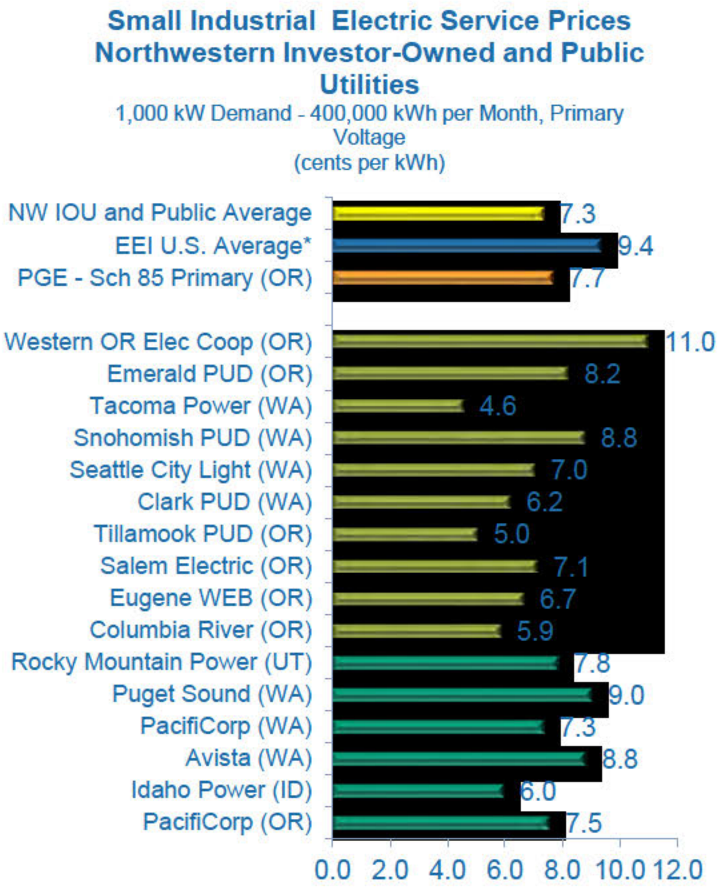


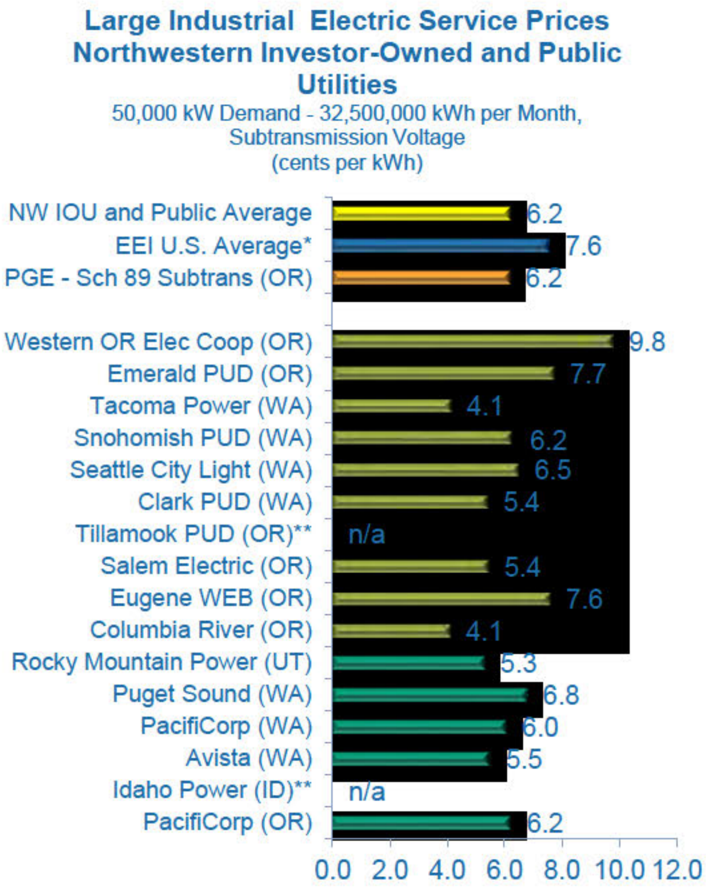


* This average is based on Investor-owned utilities only.

Average Retail Price Comparison

Small and Large Industrial – Winter 2016





* This average is based on Investor-owned utilities only.
** Idaho Power does not report a price to EEI for large industrial customers at this usage and demand level.
**Tillamook PUD does not offer a large general service tariff on their web site.

CASE: UE 319
WITNESS: PHIL BOYLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 600

Fee Free Bankcard Program

Opening Testimony

<u>REDACTED</u>
June 16, 2017

Q. Please state your name, occupation, and business address.

A. My name is Phil Boyle. I am the Consumer Services Manager with the Public Utility Commission of Oregon. My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301-3612.

Q. Please describe your educational background and work experience.

A. My educational background and work experience are set forth in my Witness Qualifications Statement, which is found in Exhibit Staff/601.

Q. What is the purpose of your testimony?

A. To discuss Portland General Electric's (PGE or Company) Fee Free Payment Program and program operating costs. PGE did not provide written testimony regarding the Fee Free Bankcard program, but program costs are embedded in PGE's rate request.

Q. Did you prepare any exhibits other than your qualification exhibit for this docket?

A. Yes. I have prepared the following exhibits:

Exhibit 601 – Witness Qualifications Statement.
Exhibit 602 – PGE's response to Staff DR No. 160 showing annual transaction costs from September 2014 through January 2017.
Exhibit 603 – Graph of Staff and PGE historical projection of transactions vs actual transactions compared to test year projections.
Exhibit 604 – PGE's response to Staff DR No.162 showing 2018 test year monthly projected transaction costs.
Exhibit 605 – (Confidential) PGE's response to Staff DR No. 353 showing monthly expected fee free bankcard adoption rate for the test period.
Exhibit 606 – (Confidential) Graph comparing Staff's calculation of payment transactions vs. PGE projections.
Exhibit 607 – (Confidential) Table comparing PGE's projected test year transactions and Staff's projected transactions.

Exhibit 608 – (Confidential) PGE's response to Staff DR No. 159 showing expected test year transactions.

Exhibit 609 – PGE response to Staff DR No. 356 answering why the cost per transaction has increased since the last rate case.

Q. How is your testimony organized?

A. My testimony first discusses the history of PGE's Fee Free Bankcard program, followed by my analysis and final recommendations.

HISTORY

Q. Describe PGE's history with a Fee Free Bankcard payment option for its customers?

A. PGE has historically accepted credit and debit card payments from customers. Prior to introduction of the Fee Free Bankcard payment option in 2014 (Docket No. UE 262), customers were required to pay a $2.95 convenience fee to the third-party vendor who actually processed the transaction. This transaction fee was retained by the vendor.

In Docket No. UE 262, the Company's 2013 General rate case, the Company requested $1.6 million in its test year revenue requirement to begin a fee free bankcard payment option for residential customers.[1] The Commission approved a settlement in which the parties agreed to $500,000 for the initial offering to occur by July 1, 2014.[2] The program start was delayed until late September 2014. For the last three months of 2014, the Company spent a total of $0.15 million for the program.

[1] UE 262 PGE/900, Stathis/Dillin/18, lines 21-22.

[2] See UE 283 PGE/1000, Stathis/Dillin/14, lines 15-16; Order No. 13-459, p. 6.

In Docket No. UE 283 (2015), the Company requested $1.8 million to continue the fee free program.[3] The parties stipulated to expense of $1.5 million in revenue requirement for the program, which was offset in 2015 by a partial refund of amounts recovered for 2014 but not used due to the delayed start.[4] Participation in 2015 was significantly less than anticipated and actual expenditures were $0.841 million.[5]

In Docket No. UE 294 (2016), the Company's 2016 test year forecast included $2.1million to continue the residential program and $0.2 million to expand the program to small non-residential customers.[6] The Commission approved a stipulation that included a downward adjustment of $8 million to PGE's test year O&M expense and a $9 million reduction to rate base to resolve several issues, including the fee free bankcard program.[7] PGE's actual expenditures for the program were $1.038 million.[8] PGE did not expand the program to non-residential customers.[9]

In each filing described above, the Company has over-estimated customer participation rates and subsequently been allowed more funding than was necessary. As a result, PGE has been allowed $3.486 million in program expense over three rate cases against a program expenditure of $2.028 million over the same period. The Company did

[3] See Order No. 14-422, pp. 4-5.
[4] Order No. 14-422, pp. 4-5.
[5] See Staff/602 showing annual transaction costs from September 2014 through January 2017.
[6] UE 294 PGE/900, Stathis-Dillin/15, lines 14-15.
[7] See Order No. 15-356 (Docket No. UE 294).
[8] See Staff/602, Showing annual transaction costs from September 2014 through January 2017.
[9] See Staff/605, PGE Response to Staff DR No. 353 (noting that only residential customers can use the fee free bankcard program at this time).

not make a specific request for 2017 funding, but costs allowed in Docket No. UE 294 appear to be adequate to cover program costs assuming adoption growth continues as trending.

STAFF'S REVIEW

Q. Did you review PGE's continuation of the Fee Free Bankcard payment option to residential customers in 2018?

A. Yes. After graphing Staff and PGE projected transactions from past rate cases against PGE's anticipated program expenditures for the test year, it became obvious that both Staff and PGE have been overly optimistic in their expectations for customer adoption of fee free bankcard payments.[10] While customer adoption rate is slowly increasing, it is not doing so as rapidly as expected. PGE's expected expenditure for 2018 of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**is more realistic than past requests, but this still presumes an adoption growth-rate that is not entirely realistic.[11]

Q. What are Staff's findings regarding the Fee Free Payment program?

A. PGE projects their fee free bankcard adoption rate at the start of 2018 to be **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and expects it to increase to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** by

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[10] See Staff/603, Graph of staff and PGE historical projection of transactions vs actual transactions compared to test year projections.

[11] See Staff/604, PGE's response to DR #162 showing 2018 test year monthly projected transaction costs.

the end of 2018.[12] Staff agrees that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** is a realistic starting point when considering the historical trend, but Staff disagrees with PGE's ramp up to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** which is much steeper than the trend. Staff believes a ramp paralleling the historical trend is more realistic, and projects a year-end 2018 adoption rate of 10.84%.[13] The difference in year-end bankcard adoption rate projections by PGE and Staff results in a differing number of payment transactions for the test period. PGE projects 1,010,180 transactions while Staff projects 910,750,[14] a difference of $99,430.

For 2015 and 2016 respectively, the average cost per transaction was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** but for 2018 it is expected to increase to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** based on data provided by the Company in response to Staff DR Nos.159[15] and 162[16] PGE does not explain the increase, but says in response to follow-up DR No. 356,[17] "When PGE developed the test year forecast, the projected cost per

[12] Staff/605(Confidential), PGE's response to DR #353 showing monthly expected fee free bankcard adoption rate.
[13] Staff/606, (Confidential) Graph comparing staff's calculation of payment transactions vs PGE projections.
[14] Staff/607 (Confidential), Table comparing PGE's projected test year transactions and staff's projected transactions.
[15] Staff/608 (Confidential), PGE's response to Staff DR No. 159 showing expected test year transactions.
[16] See Staff/604, PGE's response to DR #162 showing 2018 test year monthly projected transaction costs.
[17] Staff/609, PGE response to Staff DR No. 356 answering why the cost per transaction has increased since the last rate case.

transaction and transaction volume supported the 2018 forecast in relation to historical actuals." This response does not provide any explanation about why the transaction cost has increased by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per transaction.

Staff also asked if PGE had considered any associated savings that have occurred due to the fee free bankcard option with regard to improved cash flow, reduced write-offs, reduced mailing and postage expenses, etc. PGE responded that they have not projected any savings in the test period for these items, and says there is no basis for assuming savings at the current level adoption. Staff disagrees with this position. Staff believes there are associated savings but is unable to quantify them because PGE has not performed an associated analysis. As such, it seems reasonable to remove a portion of program costs.

Q. What does Staff recommend?

A. Staff supports the continuation of the fee free bankcard payment option, but believes PGE's projected transactions and transaction charges are too high. Also, Staff believes there are unquantified savings associated with improved cash flow, lower write-offs, lower postage and billing expenses, etc. As such, Staff proposes to reduce program costs an additional 10 percent. Staff's adjustment is based on:

1. Lower cost per transaction set at the UE 294 rate;
2. Fewer transactions based on Staff's estimated growth; and
3. 10 percent reduction for unquantified savings.

Staff's total adjustment is ($643,506), leaving $1,261,953 in PGE's 2018 Test Year for PGE's fee free bankcard program

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 319
WITNESS: PHIL BOYLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 601

Witness Qualifications Statement

June 16, 2017

WITNESS QUALIFICATIONS STATEMENT

NAME:	Phil Boyle
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Program Manager Consumer Services Section
ADDRESS:	201 High Street SE., Suite 100 Salem, OR 97301
EDUCATION:	Bachelor of Science (Education) Portland State University, 1980
EXPERIENCE:	1980 to 2003 – PacifiCorp I worked at PacifiCorp (Pacific Power) in a variety of customer facing positions over the years, starting as an Energy Consultant, progressing through Sales and Commercial Account Manager position's, to local District Manager and Customer Service Manager. In my 23 years at PacifiCorp I learned about all aspects of customer service and distribution operations. 2004 to 2005 – Oregon Department of Revenue Worked in collections unit collecting delinquent taxes. 2005 to Present – Oregon Public Utility Commission I am currently Program Manager for the Consumer Services Section, beginning my work with the PUC as a Consumer Specialist, advancing to a Senior Compliance Specialist and finally to Program Manager. In these roles I have become very experienced working with utilities to help them comply with Division 21 Administrative Rules.

CASE: UE 319
WITNESS: PHIL BOYLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 602

Exhibits in Support
Of Opening Testimony

June 16, 2017

March 21, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 160
Dated March 7, 2017

Request:

Please provide the total transaction costs by month for the Fee Free Bankcard Payment Program, by credit card and debit card if available, since the inception of the program.

Response:

Total transaction costs by month for the Fee Free Bankcard are provided below. Transaction costs include costs for both credit card and debit card, which PGE does not track separately.

Year	Month	Act Fees
2014	September	$ 1,138
2014	October	$ 50,889
2014	November	$ 43,634
2014	December	$ 55,091
2015	January	$ 66,647
2015	February	$ 69,456
2015	March	$ 70,877
2015	April	$ 68,755
2015	May	$ 67,503
2015	June	$ 65,773
2015	July	$ 68,311
2015	August	$ 72,578
2015	September	$ 70,942
2015	October	$ 76,365
2015	November	$ 67,629
2015	December	$ 75,675
2016	January	$ 83,805
2016	February	$ 89,401
2016	March	$ 89,825
2016	April	$ 91,789
2016	May	$ 81,380
2016	June	$ 81,442
2016	July	$ 82,647
2016	August	$ 88,620
2016	September	$ 87,085
2016	October	$ 89,574
2016	November	$ 82,433
2016	December	$ 89,905
2017	January	$ 100,113

CASE: UE 319
WITNESS: PHIL BOYLE

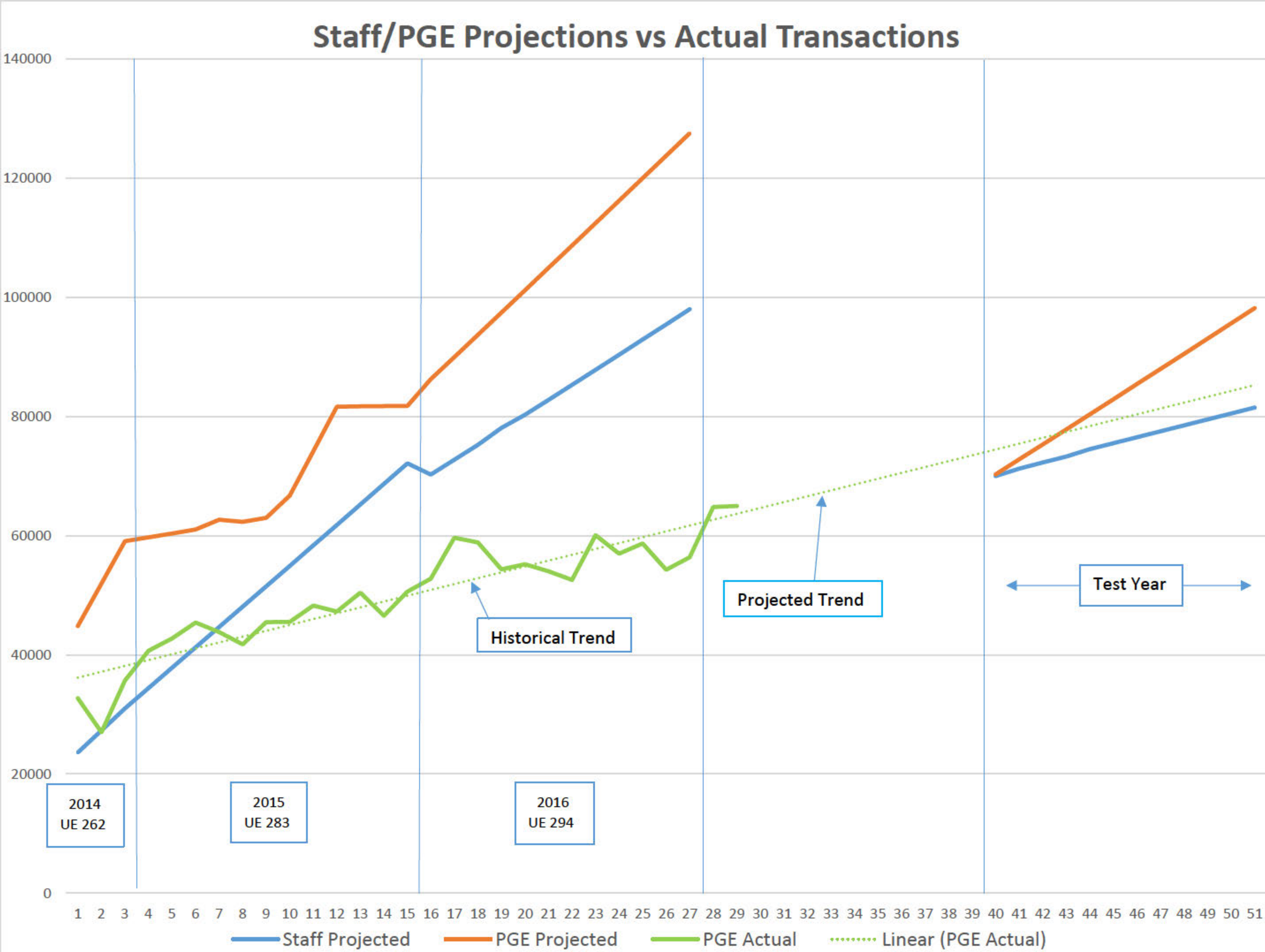
PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 603

Exhibits in Support
Of Opening Testimony

June 16, 2017

Staff Exhibit 603



CASE: UE 319
WITNESS: PHIL BOYLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 604

Exhibits in Support
Of Opening Testimony

June 16, 2017

March 21, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 162
Dated March 7, 2017

Request:

Please provide the monthly projected transaction costs, broken down by credit cards and debit cards, for the test year period.

Response:

Monthly projected transaction costs by credit card and debit card for the test period are below.

Year	Month	Credit Card	Debit Card	Total
2018	January	$110,582	$21,999	$132,582
2018	February	$114,524	$22,784	$137,308
2018	March	$118,478	$23,570	$142,049
2018	April	$122,451	$24,361	$146,811
2018	May	$126,420	$25,150	$151,570
2018	June	$130,403	$25,943	$156,346
2018	July	$134,381	$26,734	$161,115
2018	August	$138,385	$27,531	$165,916
2018	September	$142,382	$28,326	$170,708
2018	October	$146,411	$29,127	$175,538
2018	November	$150,427	$29,926	$180,353
2018	December	$154,440	$30,725	$185,165
	Total	**$1,589,285**	**$316,174**	**$1,905,459**

CASE: UE 319
WITNESS: PHIL BOYLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 605

Exhibits in Support
Of Opening Testimony

June 16, 2017

April 10, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 353
Dated March 27, 2017

Request:

By month, for the test period, please provide the percentage of total residential customers that PGE projects will use the fee free card program.

Response:

PGE interprets "the percentage of total residential customers" to be the adoption rate of Fee Free Bank Card (FFBC) users. At this time, only residential customers can use the FFBC. See Attachment 353-A for the percentage of total residential payment transactions in which customers pay with a FFBC that PGE projects in the 2018 test period.

Attachment 353-A is protected information subject to Protective Order No. 17-057.

UE 319

Attachment 353-A

Provided in Electronic Format only

Protected Information Subject to Protective Order No. 17-057

Projected Fee Free Bank Card Adoption Rate in 2018

This page is confidential and is subject to

Protective Order No. 17-057

CASE: UE 319
WITNESS: PHIL BOYLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 606

Exhibits in Support
Of Opening Testimony

June 16, 2017

Staff Exhibit 606 is confidential and

Is subject to Protective Order No.17-057

CASE: UE 319
WITNESS: PHIL BOYLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 607

Exhibits in Support
Of Opening Testimony

June 16, 2017

Staff Exhibit 607 is confidential and

Is subject to Protective Order No.17-057

CASE: UE 319
WITNESS: PHIL BOYLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 608

Exhibits in Support
Of Opening Testimony

June 16, 2017

This page is confidential and is subject to

Protective Order No. 17-057

CASE: UE 319
WITNESS: PHIL BOYLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 609

Exhibits in Support
Of Opening Testimony

June 16, 2017

April 10, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 356
Dated March 27, 2017

Request:

Data provided in response to DR 160 indicates a historical average cost per transaction of $1.54. Data provided in response to DR 162 indicates a projected cost of $1.89 per transaction in the test year. Please explain the factors leading to the transaction cost increase, and provide any documentation which supports this.

Response:

When PGE developed the test year forecast, the projected cost per transaction and transaction volume supported the 2018 forecast in relation to the historical actuals.

CASE: UE 319
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 700

Opening Testimony

REDACTED

June 16, 2017

Q. Please state your name, occupation, and business address.

A. My name is Dr. Lance Kaufman. I am a Senior Utility Analyst employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/201.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address issues related to revenue, expenses, and rate base in PGE's opening testimony.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following exhibits:

Staff/701 Responses to OPUC Data Requests
Staff/702 Port Westward Planned Outages CONFIDENTIAL
Staff/703 Hinge Fit Sensitivity Analysis
Staff/704 Residential Sales Forecast
Staff/705 Other Revenue Forecast Variance
Staff/706 Major Maintenance Accrual Balancing Accounts

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. What are your recommendations regarding these issues?

A. Staff makes the following recommendations:

1. Residential Retail Sales
    a. Increase forecasted revenue by $15,544,991.
2. Other Revenue
    a. Increase forecasted other revenue by $2.9 million.
3. Carty Rate base
    a. Reduce Carty rate base by $7.7 million.
    b. Reduce Carty depreciation expense by $1.66 million.
4. Major Maintenance Accruals (MMA)
    a. Do not allow deferred expenses in the calculation of existing MMA balancing accounts, increase net balance by $7.7 million (and reduce rate base by equivalent amount.)
    b. Use a projected three year moving average of major maintenenace expense for Colestrip, which increases expense by $244,240 relative to PGE's proposed Colstrip MMA.
    c. Eliminate existing MMA of gas plants from base rates, reduce revenue requirement by $13,924,362.
    d. Return balance of MMA account to customers, reduce revenue reqirement by $12,740,793.
    e. Include 2018 gas major maintenance expense in NVPC, increase NVPC forecast by $14,936,789.
5. Generation Operations and Maintenance Labor
    a. Eliminate FTE for 13 Generation Operation and Maintenance FTE through addoption of Staff/400 general labor adjustment. Reduce outside services expense by $90,000.
6. Decoupling
    a. Accept PGE's filed changes to Schedule 123.
7. Security
    a. Eliminate 3 Security FTE through adoption of Staff/400 general labor adjustment.
8. Affiliated Interests
    a. Accept PGE's current allocations and affiliated interest transactions subject to continued Staff review.

ISSUE 1: RESIDENTIAL RETAIL SALES

Q. Please summarize this issue and your recommended treatment.

A. PGE forecasts residential sales of $922.6 million in 2018.[1] Staff raises several concerns with PGE's forecast method in this testimony. Some of these concerns have been raised by Staff in past proceedings. Staff performed a statistical analysis of PGE's residential sales and finds that 2018 residential sales are more likely to be $938.2 million.[2] Staff recommends calculating rates using Staff's forecast of residential customers and residential customer counts.

Q. What is PGE's proposed treatment of normal weather?

A. PGE proposes to calculate normal weather by projecting a historic trend beginning in 1975.[3] PGE refers to this as the Hinge Fit model.[4] This is a departure from PGE's historic use a 15-year rolling average. The impact of this projection is that PGE forecasts fewer heating degree days and more cooling degree days relative to the 15-year average weather.[5]

Q. How does the Hinge Fit model affect the sales forecast?

A. The majority of PGE's weather sensitive load is related to heating rather than cooling. For this reason, PGE's approach results in lower sales forecasts compared to the use of a 15 year average. This is because the Hinge Fit model results in a warmer normal than using the 15-year rolling average. With warmer weather, less electricity is needed to heat homes.

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[1] PGE/1402, Cody – Macfarlane/1.
[2] *See* Staff/704, Kaufman/2.
[3] PGE/1200, Dammen – Riter/7 at lines 6 to 9.
[4] PGE/1200, Dammen – Riter/6 at line 20.
[5] PGE/1211.

Q. Please provide a summary of your conclusions regarding PGE's trended weather approach.

A. PGE's proposed approach is one method of incorporating climate change into a weather forecast. PGE's approach is more sophisticated than the current approaches used by Oregon utilities. In general, Staff is willing to consider the use of a more sophisticated approach to long range weather forecasts. However, there are many modeling decisions involved in developing a more sophisticated forecast. Due to the wide range of discretionary options in trend forecasting and due to the industry support for the historic average method, forecasts used to set rates should continue to rely on a simple historic averaging approach.

Q. What analysis lead you to this conclusion?

A. Staff considered the following items:

- Weather trend research referenced by PGE;
- Methods used by US National Weather Service Climate Prediction Center;
- Sensitivity of PGE's trending analysis;
- Comparison of the Hinge Fit model to the Optimal Climate Normals model; and
- Methods used by other utilities.

Q. Please summarize your findings regarding the weather trend research reference by PGE.

A. PGE's model is based on research presented in "*Estimation and Extrapolation of Climate Normals and Climatic Trends.*"[6] Staff reviewed this article and found that the conclusions in the article do not support PGE's use of a trending model. The article evaluates the performance of World Meteorological Organization (WMO) recommended weather normal against three alternate approaches:

- Optimal Climate Normals (OCN) or historical rolling averages;
- Linear trending; and
- Hinged linear trending, or the Hinge Fit model.

A key aspect of this study is that the WMO normals are substantially different from normal weather currently used by PGE. WMO normals are calculated using 30-year averages, updated every 30 years. WMO normals can at times use data that is 60 years old. On the other hand PGE's historic approach used a 15-year rolling average, which is updated every year. This results in using data that is at most 16 years old. The 15-year rolling average method does not become out of date to the same degree that the WMO method does. In fact, the 15-year rolling average is very similar to the OCN method.[7] The study

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[6] Livezey, Robert E. et al. "Estimation and Extrapolation of Climate Normals and Climatic Trends." *Journal of Applied Meteorology and Climatology*, vol. 46, 2007, pp. 1759-1776, http://www.meto.umd.edu/~kostya/Pdf/Livezey_et_al_2007.pdf Accessed June 11, 2017.

[7] The OCN approach uses 10 year rolling averages for temperature, and 15 year rolling averages for precipitation. Livezey et al. page 1765. The NOAA Local Climate Analysis Tool, which is based on this research, includes a OCN model that uses 15 years for the OCN model. This tool is available at http://nws.weather.gov/lcat/.

reference by PGE supports the use of the OCN method, particularly for short term forecasts. The study states "OCN method implemented with flexible averaging periods only begins to fail for very strong underlying trends (between 0.5 and 1 standard deviation of the residual noise per decade) or for longer extrapolations with more moderate background trend."[8] This statement supports Staff's recommendation that the rolling 15-year average approach continue to be used for the short term forecasts in this docket, but that parties consider a more sophisticated weather model when producing long term, multi-year forecasts.

The study notes that the U.S. National Weather Service Climate Prediction Center (CPC) currently utilizes the OCN method for one year forecasts.[9]

Q. What method is used by the Climate Prediction Center for short term forecasts?

A. The CPC currently utilizes the OCN method for one year forecasts.[10] The CPC has greater expertise than PGE with respect to weather forecasting. The CPC is a branch of the National Weather Service. The mission of the national weather service is to provide:

> [W]eather, hydrologic, and climate forecasts and warnings for the United States, its territories, adjacent waters and ocean areas, for the protection of life and property and the enhancement of the national economy. NWS data and products form a national information database and infrastructure which can be used by other governmental agencies, the private sector, the public, and the global community.

[8] Livezey et al. page 1771.
[9] Livezey et al. page 1765.
[10] Livezey et al. page 1765.

This agency's methodology for one year forecasts is much more similar to PGE's current method than PGE's proposed method.

Q. What sensitivity analysis did you perform on the Hinge Fit model?

A. I evaluated three aspects of the sensitivity of the Hinge Fit model results:

1. Weather Station
2. Forecast Month
3. Historic Time Period

Q. Please summarize your results for the Hinge Fit sensitivity analysis.

A. The trend estimates from the Hinge Fit model are highly sensitive to weather station, month, and historic time period. Staff evaluated the trend estimate for four weather stations located in and around Portland.[11] The December trend estimate ranged from a high of 0.004 degrees per year to a low of a negative 0.009 degrees per year.[12] The average trend was negative 0.002 degrees per year.[13] The trend switched sign, and the range in trend was six times larger than the average trend.

Staff evaluated the same weather stations for the January trend. The average January trend was 0.099 degrees per year.[14] From December to January the average trend switches sign. Staff would expect that if Portland was experiencing changing winter temperatures, the impact of December would be in the same direction as January. The fact that the Hinge Fit forecast

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[11] This analysis is based on the NOAA hinge-fit model included as part of the Local Climate Analysis Tool at http://nws.weather.gov/lcat/. This tool appears to be developed by the same team that authored the reports reference by PGE to support the use of the Hinge Fit model.
[12] Staff/703, Kaufman/1.
[13] Staff/703, Kaufman/1.
[14] Staff/703, Kaufman/1.

switches signs within the same month for different stations and across months for the same stations indicates that the forecast has low precision.

Staff evaluated the December Trend at the Portland Airport weather station using successively earlier ending periods for the historic data used to estimate the trend. The trend estimate decreases substantially when the most recent two years of data are excluded from the historic data set.[15]

All three sensitivity analyses show that the Hinge Fit model is highly sensitive to the tested inputs.

Q. How does the Hinge Fit model compare to the OCN model?

A. These two models have comparable results. Staff reviewed the Root Mean Squared Error for each model. The OCN model outperformed the Hinge Fit model in estimating January weather,[16] however the Hinge fit model outperformed the OCN model in estimating December.[17]

Staff also reviewed the recent five year performance of the two models.[18] Both models had periods of under forecasting and over forecasting weather in the last five years.

Q. If the Hinge Fit model is more sophisticated than the OCN model, why do they have similar performance?

A. The two models excel at capturing different aspects of evolving weather patterns. OCN is simpler than the Hinge Fit, but it is more responsive to cyclical patterns. The Hinge Fit model is capable of anticipating a trend in the

[15] Staff/703, Kaufman/1.
[16] Staff/703, Kaufman/4.
[17] Staff/703, Kaufman/8.
[18] Staff/703, Kaufman/2 and 6.

data, but it does not account for cycles. Both models perform similarly in the short run. However, it is possible that for a long run forecast the Hinge Fit model would perform better. Staff will continue to compare the performance of these two models and report any meaningful results in subsequent testimony.

Q. How do regulated Oregon utilities currently forecast weather?

A. Oregon utilities currently use a method that is very similar to the OCN model. The main difference is that utilities average over different numbers of years, ranging between 15 to 30 year averages when forecasting normal weather. The table below provides a summary for each utility.

Utility	Normal Weather	Source
Avista Utilities	20 Years	Docket No. UG 325 Avista/700 Forsythe/12
Cascade Natural Gas	30 Years	Staff email
Northwest Natural	25 Years	Staff email
PacifiCorp	20 Years	Docket No. UE 323 DR No. 1
Portland General Electric	15 Years	PGE/200 Dammen – Riter/5
Idaho Power Company	30 years (15 for Res CDD)	Staff email

Q. What is Staff's current approach to weather forecasting for the various OPUC filings?

A. Staff seeks to have consistent treatment across utilities and types of filings. Staff recognizes that each utility may have different circumstances, and that different types of filings often have different areas of emphasis for forecasting. For example, long term forecasts and estimation of the range of a high and low outcomes are particularly important in integrated resource planning relative to rate cases. In this round of testimony Staff is adopting PGE's historically used 15-year averages for normal weather. Staff understands that a 15-year period may be too short to appropriately normalize short term fluctuations in weather.

For this reason, Staff does not intend the use of 15 years in this testimony to indicate support for 15 years in future filings or for other utilities. Staff needs to perform additional analysis before making a final determination on number of years to include in normal weather for application in other dockets.

Q. What is Staff's proposed forecast of residential sales?

A. Staff forecasts total 2018 residential energy deliveries of 7,702 million kWh.[19] This is 1.9 percent higher than PGE's proposed forecast.

Q. How does Staff's forecast affect 2018 revenues?

A. Staff forecasts 2018 residential sales revenue to be $938.2 million.[20] Relative to PGE's forecast this increases 2018 revenues at current rates by $15,544,991.[21]

Q. Please summarize how Staff's forecast is generated.

A. Staff uses a similar forecast model as PGE with the following changes:

- Staff combines the energy efficiency adjustment into the main forecast model rather than performing an out-board adjustment.
- Staff uses consistent weather response variables across all residential groups.
- Staff eliminates the use of model fitting dummy variables.
- Staff automates the model selection process using a computer algorithm that minimizes each model's information loss.

[19] *See* Staff/704, Kaufman/1.
[20] *See* Staff/704, Kaufman/2.
[21] *See* Staff/704, Kaufman/2.

Q. What is the primary factor driving the difference between Staff's proposal and PGE's proposal?

A. The primary difference is the use of 15-year average weather data rather than the Hinge Fit model. This aspect of the forecast should be the Commission's primary focus when determining which model to select.

Q. Please summarize Staff's recommendation.

A. Staff recommends the Commission adopt Staff's proposed forecast methodology.[22] If the Commission finds that PGE's model should be used, Staff recommends that PGE's model be modified to use a 15-year normal weather forecast, as that is more consistent with the current industry standards for short term weather forecasting. Staff recommends that PGE be encouraged to continue exploring the appropriate application of a more sophisticated approach to weather forecasting for forecasts that are long term. Staff intends to work with other utilities as well with the goal of developing a consistent approach across companies for estimating normal weather.

[22] The specific formulas and programs are included in Staff workpapers for this testimony.

ISSUE 2: OTHER REVENUE

Q. Please summarize this issue and your recommended treatment.

A. PGE's primary sources of other revenue are "rent of electric property, transmission revenue, joint-pole revenue, steam sales revenue, and ancillary service revenue."[23] PGE forecasts other revenue to decrease from $26.7 million in 2016 to $25.8 million in 2018.[24] PGE attributes the decline to the completion of a fiber deployment project and declining pole attachment rates. Staff finds that PGE's forecast method accounts for declines in revenues but does not consistently anticipate new revenue. Staff forecasts 2018 other revenue to be $28,735,000. Staff recommends the Commission use Staff's forecast of 2018 other revenue.

Q. Please summarize the historic performance of PGE's other revenue forecasts.

A. PGE has under-forecasted other revenue in every rate case since 2006. Staff did not evaluate PGE's forecasts prior to 2006. On average PGE's forecasts are $2.9 million below the actual value. Staff/705 provides the forecasted and actual values from PGE's rate cases.

Q. How has the Commission treated PGE's other revenue forecast in past rate cases?

A. In Docket No. UE 294 the Commission increased PGE's forecast by $1.5 million.[25] Even with this adjustment the Commission allowance of other

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[23] PGE/200, Tooman – Brown/5 at lines 9 to 11.
[24] PGE/202.
[25] Order 15-356 page 9.

revenue fell short of actual revenue by $80,000 dollars. In Docket No. UE 283 the Commission increased PGE's other revenue by $1.31 million.[26] In Docket No. UE 262 the Commission increased PGE's other revenue by $749,000.[27] In Docket UE 215 the Commission increased PGE's other revenue by $0.966 million.[28]

Q. What has caused PGE to under-forecast other revenue in the past?

A. PGE's historic method of forecasting other revenue does not seem to accurately predict increases in revenue. PGE provided Staff with comments related to the variance in other revenue from actuals to budget for 2010 through 2016. These comments are presented in Staff/705.

Q. Is it reasonable for PGE to have difficulty forecasting revenue increases than decreases?

A. Yes, this is reasonable. Forecasting new sources of revenue requires anticipating something that does not currently exist. Because PGE may not have knowledge of new revenue sources when forecasting revenue, PGE cannot easily gather data to inform the forecast. However, when forecasting decreases in revenue PGE can review existing data on current revenue sources. This makes forecasting declines in existing revenue easier than forecasting new revenue sources.

[26] Order 14-422 page 3.
[27] Order 13-459 page 4.
[28] Order 10-478 page 10.

Q. Please explain Staff's recommendation regarding other revenue.

A. PGE's historic method of forecasting other revenue is unable to accurately anticipate all new revenue sources in rate case years. PGE has not modified its forecast process from that used in previous cases.[29] As a result, PGE's proposed forecast is likely to under forecast other revenue by $2.9 million. Staff recommends increasing other revenue by $2.9 million to account for unanticipated new revenue sources in 2018.

[29] Staff/701, Kaufman/22, PGE response to OPUC DR No. 412 part d.

ISSUE 3: CARTY RATE BASE

Q. Please summarize this issue and your recommended treatment.

A. In PGE's last rate case, Docket No. UE 294, PGE requested to include the cost of a new generation plant, Carty, into base rates. Carty was forecasted to cost $514 million, including the supporting transmission facilities. Parties settled all issues related in Docket No. UE 294 several months before Carty became operational. Parties stipulated to the inclusion of the forecasted $514 million, and that PGE would be required to request rate recovery in a separate ratemaking proceeding for amounts above $514 million.[30] PGE experienced construction difficulties and delays caused Carty to be placed in service 75 days later than expected.[31] The overall actual cost to build Carty appears to be around $660 million, however the final cost remains unknown until certain lawsuits are resolved.[32] PGE has requested to increase the rate base associated with Carty by $7.7 million to $521.7 million.[33] PGE attributes this increase to the additional Allowance for Funds Used During Constructions (AFUDC)[34] resulting from Carty construction delays.[35]

Staff requested documentation the Carty investment in order to establish whether the construction of Carty was prudently managed given that actual costs exceed the amount stipulated to in UE 294. PGE has objected to these data requests on the grounds that the data may interfere with certain

[30] PGE/200, Tooman – Brown/15.
[31] PGE/200, Tooman – Brown/16.
[32] Docket No. UM 1791, Application for Deferral of Incremental Revenue Requirement Associated with the Carty Generating Station page 7.
[33] PGE/200, Tooman – Brown/16.
[34] PGE's testimony uses the acronym AFDC for this term.
[35] PGE/200, Tooman – Brown/16.

lawsuits.[36] Staff agrees that a prudence determination of the Carty investment can be made at a later date; however, until such time it is not appropriate to increase the rate base for Carty beyond the original stipulation. Staff recommends the Commission exclude the additional $7.7 million of rate base and withhold a prudence judgement regarding PGE's management of Carty for a future proceeding.

Q. Please describe what AFUDC is and explain why PGE is requesting additional AFUDC.

A. AFUDC is an allowance for the cost of capital used during construction. This allowance is a rate applied to the balance of funds used during construction. PGE is requesting additional AFUDC because the initial estimate in Docket No. UE 294 was based on an earlier in-service date than Carty actually experienced.[37]

Q. Did you find any issues with how PGE calculated the additional AFUDC for Carty?

A. Yes, I observed two issues; first, PGE claims to have a relatively high AFUDC rate. This may be because PGE does not fund construction in a least cost manner. Staff is continuing to investigate the appropriate AFUDC rate as described further in Staff/500, Opening Testimony of Matt Muldoon. Second, PGE's calculation of AFUDC implies that all Carty rate base was transferred to plant in July, 2016. However, as explained below some Carty rate base was not transferred to plant until December, 2016. Staff cannot

[36] Staff/701, Kaufman/11 to 18. PGE response to OPUC DR 145 to 152.
[37] PGE/200, Tooman – Brown/16.

confirm the accuracy of PGE's AFUDC calculations until this issue is clearly explained.

Q. Does the UE 294 stipulation address the treatment of AFUDC in a subsequent rate proceeding?

A. No. The parties to UE 294 did not stipulate to the future ratemaking treatment of additional AFUDC above amounts included in UE 294.[38] Additional amounts of AFUDC should be reviewed and addressed in a future ratemaking proceeding that addresses the prudence of PGE's management of Carty's construction.

Q. What did Staff review when investigating this issue?

A. Staff reviewed the following:

- Workpapers calculating Carty AFUDC;
- Documentation of Carty's transfers to plant; and
- PGE current and prior testimony.

Q. What concerns did this review raise for Staff?

A. Staff's review raised the following concerns:

- PGE has a higher than expected AFUDC rate.
- PGE AFUDC calculations are not consistent with PGE transfers to plant.
- In the July 27, 2016 compliance filing, PGE incorporated rate base into rates that did not transfer to plant until December, 2016.

[38] *See In re Portland General Electric*, OPUC docket No. UE 294, Order No. 15-356, Appendix A at 4-5 (Nov. 3, 2015).

- PGE may have incurred higher costs than necessary in order to speed up the construction of Carty.

Staff has not been able to investigate these issues further due to PGE's decision to not provide discovery related to PGE's management of Carty.

Q. Please explain your recommended treatment of Carty rate base.

A. Staff recommends that Carty gross plant in rate base be limited to $514 million until such time as PGE's management of the project can be evaluated by Staff. PGE has requested that Staff not investigate the prudence of PGE's management of Carty in this case and Staff has agreed. This results in a reduction to PGE's rate base of $7.7 million.

Q. What is the impact of your recommendation?

A. The impact of my recommendation has two components. The first component is that lower rate base reduces the return on rate base, tax expense, and other revenue sensitive items. These impacts are addressed in the opening testimony of Marianne Gardner in Staff/400.

The second component is that depreciation expense is lower. Staff estimates that the reduction to depreciation expense is approximately $1.66 million. Staff observed the following inconsistencies in PGE's workpapers calculating depreciation expense:

1. Depreciation expense was calculated for 2017, not 2018;
2. Depreciation expense does not match the amount included in PGE's testimony;
3. Depreciation expense appears to double recover salvage.

Staff recommends that the final depreciation impact be calculated after these inconsistencies have been resolved.

ISSUE 4: MAJOR MAINTENANCE ACCRUALS

Q. Please summarize this issue and your recommended treatment.

A. PGE is requesting that costs associated with the major maintenance of its gas and coal plants be accrued based on a five year forecast (2018 through 2022). PGE currently uses major maintenance accruals (MMA) in this manner for four gas plants, Carty, Coyote, Port Westward 1 and Port Westward 2. PGE is requesting that the MMA mechanism be extended to Colstrip. In PGE's last rate case PGE based maintenance expense for Carty on the maintenance that was expected to occur within the test year. Staff finds that the major maintenance expense for PGE's gas plants are directly related to the hours of operation. Staff recommends that the major maintenance expense for PGE's gas plants be recovered through PGE's NVPC mechanisms. Staff recommends that Colstrip's major maintenance expense be calculated using a three year moving average of forecasted expenses.

Q. What is PGE's proposed maintenance expense for the test year?

A. PGE proposes a major maintenance accrual of $16.3 million for 2018.[39]

Q. How has the Commission historically treated PGE's major maintenance expenses?

A. The Commission has previously accepted PGE's proposed accrual treatment for four gas plants. This is the first case that PGE has requested accrual of coal maintenance expenses. In prior cases, the Commission allowed actual test year coal major maintenance expenses to enter rates.

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[39] PGE/700, Jenkins – Rodehorst/14.

Q. What concerns does Staff have with PGE's major maintenance accrual method?

A. Staff has the following concerns regarding PGE's existing MMAs for its four gas plants as well as adding an MMA for Colstrip:

- PGE may be deferring expenses without filing a request to defer under ORS 757.259.
- The current treatment allows PGE to over recover maintenance expense.
- The current treatment allows PGE to accrue large balances within the MMA balancing accounts.
- Most gas generator maintenance is directly related to hours of operation.

Q. What evidence is there that PGE is deferring expenses?

A. The fundamental difference between an accrual and a deferral relates to the timing of a cash expenditure and the accounting recognition of the expense. In an accrual, an expense is accounted for before the cash expenditure.[40] In a deferral, an expense is accounted for after the cash expenditure.[41] PGE's workpapers indicate that it has deferred $9 million in major maintenance expenses since it has begun its major maintenance accrual process.[42] PGE's workpapers describe the treatment as a deferral. PGE has not filed for deferral of these expenses, however PGE is asking the Commission to recognize the expenses in rates through the major maintenance accrual workpapers. Staff

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[40] Financial Accounting, 11th Edition. Harrison, Horngren, Thomas & Tietz, 2017, Pearson. "An accrual is the opposite of a deferral. For an accrued *expense*, The … Company records the expense before paying cash." Page 128.

[41] Financial Accounting, 11th Edition. Harrison, Horngren, Thomas & Tietz, 2017, Pearson. "A deferral is an adjustment for payment of an item … in advance." Page 128.

[42] Staff/706, Kaufman/1 to 4 Deferred Expense column.

proposes that the existing major maintenance balancing accounts be calculated exclusive of the historic deferred expenses. PGE proposes that the current balance of the account be recognized at ($5 million).[43] After eliminating the deferred expenses from the account Staff calculates the actual balance to be ($12.7 million).[44]

Q. How does the current treatment allow PGE to over recover maintenance expense?

A. PGE's major maintenance accrual accounting treatment includes the use of a balancing account to record accruals and expenses. In Staff's experience evaluating other balancing accounts, the amount credited to the account is tied to actual sales. Under PGE's mechanism, base rates include a fixed amount per kWh that is attributable to the major maintenance accrual. As the Company sales increase the annual amount credited to the balancing account should also increase. PGE does not recognize the increased contribution of sales growth to major maintenance when calculating the major maintenance accrual balancing account. Staff has not calculated the impact of this on the major maintenance balancing account and will provide an update to the impact that this has had on the balancing account in following testimony.

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[43] *See* Staff/706, Kaufman/7 summarized from Kaufman/6.
[44] *See* Staff/706, Kaufman/7 summarized from Kaufman/5. Staff found that PGE included $9 million in deferred expenses, however, Staff's proposed balance is not $9 million less than PGE's proposal. This is because Staff's calculations are based on more recent expense data than the data included in PGE's initial filing.

Q. The current balance of the MMA balancing accounts seems large. How large have these balances gotten and why were they able to get so large?

A. Inclusive of the deferred expenses, the Coyote Springs MMA balancing account reached a maximum credit to customers of $8.2 million.[45] Exclusive of the deferred expenses the Coyote account reached a maximum credit of $14.4 million.[46] The balances got this large because PGE only updates the annual accrual amount at each rate case.

Q. Please explain why gas maintenance is directly related to hours of operation.

A. PGE's filing claims that gas plant "Major maintenance costs can vary dramatically from year to year."[47] However the forecasted expenses in PGE/703 do not have substantial year-to-year variation. The little variation that does occur is related to yearly changes in forecasted generation. PGE contracts with third parties to perform major maintenance on its gas generators. These contracts have a fixed annual charge and a cost per hour of operation charge. The variable component is approximately 93 percent of the total major maintenance cost. The variable component is estimated using output from PGE's NVPC dispatch model, MONET.

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[45] *See* Staff/706, Kaufman/2 PGE Ending Balance Year 2008.
[46] *See* Staff/706, Kaufman/2 Staff Ending Balance Year 2008.
[47] PGE/700, Jenkins – Rodehorst/12 at line 2.

Q. What is Staff's recommended treatment of the major maintenance expenses?

A. Staff recommends that Colstrip's major maintenance expense be calculated using a three year moving average of forecasted expenses. Staff recommends that gas plant major maintenance expense be recovered directly through PGE's NVPC mechanism because there is a direct relationship between generation and maintenance expense.

Q. Why do you recommend different treatment of major maintenance for Colstrip and PGE's gas plants?

A. Colstrip major maintenance expenses vary significantly on a three year cycle. Colstrip major maintenance is also not directly related to the number of operating hours.

Q. What are the benefits of recovering gas generation maintenance expense through the NVPC mechanisms?

A. This approach has the following benefits:

- Lower time lag between expense and recovery of expense;
- Better alignment with the cost causer cost payer principle;
- Reduced probability of over recovery of expense; and
- Reduces regulatory burden associated with deferral of expenses.

Q. Please provide additional details about how Staff's recommendation would be implemented.

A. Staff's proposal has four components. The first component removes the Colstrip maintenance accrual expense and replaces it with a projected three year moving average. The net impact of this increases PGE's Colstrip major maintenance expense by $244,230. The second component adjusts rate base to be consistent with the balance of the MMA balancing account, exclusive of deferred expenses. This reduces rate base ($7,659,996). The third component eliminates the gas plant maintenance accruals ($13,924,362). Because the accruals are no longer used, Staff returns the remaining balance of PGE's MMA balancing account to customers ($12,740,793). The fourth component is implemented within PGE's NVPC filings, and incorporates gas plant major maintenance into the calculation of NVPC, increasing NVPC by $13,696,953.[48] This proposal does not address Beaver major maintenance as PGE has not proposed a major maintenance deferral for Beaver. Staff is continuing to investigate the appropriate treatment of Beaver major maintenance costs. The net impact of Staff's recommendation is a reduction to 2018 base rate revenue requirement of $(26,420,925) and an increase to 2018 NVPC of $14,936,789. The change to NVPC largely offsets the elimination of the 2018 MMA accrual. The combined expense impact is only ($11,484,135). This appears like a large adjustment, however the majority of this adjustment is simply the return to customers of the pre-paid balance in the MMA balancing accounts.

[48] This is consistent with Staff's proposal in Staff/200.

Q. Has Staff identified any other accrual mechanisms that may have similar issues as the MMA?

A. Yes. In response to OPUC DR 362 PGE notes that four other items are amortized in a similar manner. Staff intends to review the amortized amounts for these items to confirm that they do not contain deferred expenses that have not been authorized by the Commission.[49]

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[49] Staff/701, Kaufman/20 Response to OPUC DR 362.

ISSUE 5: PRODUCTION OPERATIONS AND MAINTENANCE LABOR

Q. Please summarize this issue and your recommended treatment.

A. PGE proposes increasing production operations and maintenance labor by 32 FTE.[50] Staff requested detailed information about 17 of these FTE and found that the majority of the FTE either did not have cost reductions correctly accounted for, or were not justified based on PGE's labor needs.[51] Staff recommends eliminating 13 FTE from the Staff labor model and reducing contract expenses by $90,000.

Q. What do you recommend regarding the Port Westward Generation Technicians?

A. PGE proposes adding three generation technicians to the Port Westward maintenance crew. The annual cost for these positions is $266,073.[52] PGE claims that adding these that adding these FTE will reduce overtime expense by $250,000 per year, and that PGE has appropriately modified the test year budget to account for this. Given that the cost of these technicians is greater than the benefit Staff recommends eliminating PGE's proposed increase of three FTEs for generation technicians. If the Commission adopts the general labor adjustment recommended in Staff/400 PGE's adjustments to overtime expense associated with these FTE will be excluded as well.

When reviewing this issue, Staff noted that PGE's 2018 budget for Port Westward maintenance overtime is not calculated correctly. PGE budgets

[50] PGE/702.
[51] Staff/701, Kaufman/25 to 41. PGE response to OPUC DRs 618, 619, and 626.
[52] Staff/701, Kaufman/47. Calculated as three times the annual salary. This value does not include the payroll loadings such as healthcare.

$459,663 in labor overtime for the maintenance of PW1 and PW2 for 2018. The 2016 actual amount of overtime expense was $406,331. After reducing for the overtime savings of the three new technicians, and adjusting for labor escalations, the total overtime budget for 2018 should be only $176,796. PGE over budgets for 2018 overtime by $280,000. If the labor expense proposed by Staff in Staff/400 is adopted there is no need for additional adjustments related to PGE's over-forecast of overtime. If Staff's proposed general labor adjustment is not accepted by the Commission then PGE's requested labor expense should be reduced by $280,000 to account for the budget error. PGE claims that 2016 is not a representative year of maintenance expense at PW1 due to extended planned outages.[53] **[BEGIN CONFIDENTIAL]** [redacted][54] **[END CONFIDENTIAL]**

Q. What do you recommend regarding the Trojan Independent Spent Fuel Storage Installation Technician?

A. PGE expects to be reimbursed for expenses related to the Independent Spent Fuel Storage Installation technician.[55] PGE has not accounted for this reimbursement in this rate case.[56] Staff recommends that the FTE be excluded from rates. As an alternative, the anticipated reimbursement for these technicians could be included in rates.

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[53] *See* Staff/701, Kaufman/31 PGE's response to OPUC DR 626 part d.
[54] Staff/702 PW1 Forced outage rate in April Monet update workpapers.
[55] *See* Staff/701, Kaufman/31 PGE's response to OPUC DR 626 part c.
[56] *See* Staff/701, Kaufman/31 PGE's response to OPUC DR 626 part c.

Q. What do you recommend regarding the Carty Generating Technician?

A. PGE is requesting an incremental generating technician to support planning at the Carty station. However, PGE also states that the number of FTE at Carty is consistent with the number included in UE 294.[57] Because of this, Staff recommends no incremental increase in FTE related to the Carty station.

Q. What do you recommend regarding the PSES Services Analyst?

A. PGE claims that this FTE is added to the Reliability, Performance, and Monitoring (RPM) center. The original internal request for this FTE indicated that it would reduce expenses by $350,000. PGE provided workpapers showing a $260,000 reduction to the 2017 budget associated with this FTE.[58] However, Staff was not able to tie PGE's adjustment all the way to PGE's filed revenue requirement. Staff is continuing to investigate this issue. At this time, Staff recommends an additional $90,000 reduction in expenses associated with the difference between the initial estimate and the reduction that PGE indicates was incorporated into this case.

Q. What do you recommend regarding the Power Supply Engineering Services (PSES) IT Analyst?

A. PGE proposes adding one FTE as a dedicated IT resource for generation facilities. In response to a Staff data request PGE states that this FTE was double counted in another department, and that the FTE is expected to reduce the time resolving generation issues.[59] Staff recommends eliminating this FTE

[57] Staff/701, Kaufman/32 PGE response to OPUC DR 626.
[58] Staff/701, Kaufman/32 PGE response to OPUC DR 626.
[59] Staff/701, Kaufman/33 PGE response to OPUC DR 626.

from this department due to the duplication in another department. To the extent that IT issues affect the performance of PGE's generating units Staff also recommends that the forced outage rate of PGE's generation units be updated in the next Monet update. To the extent that this position does not improve the performance of PGE's generating units Staff recommends that the FTE also be eliminated from both departments.

Q. What do you recommend regarding the PGE Technical Writer Specialist?

A. PGE proposes adding one FTE to assist in the development of new generation procedures. PGE indicates in response to OPUC DR 626 part h that PGE currently has generation procedures for each plant.[60] PGE also indicates that it has already developed 75 new "common Generation Fleet Procedures."[61] Given that the prior FTE level was sufficient to create the existing generation procedures, and that there does not seem to be a pressing need for new procedures, Staff recommends excluding this FTE as an incremental FTE.

Q. What do you recommend regarding the Generations Project Manager?

A. PGE proposes adding one FTE to assist in the management of generation projects. PGE indicates in response to OPUC DR 626 part i that PGE managed 10 generation projects each year in 2015 and 2016, but only has seven projects scheduled for 2018.[62] Staff recommends excluding this FTE as an incremental FTE because PGE's 2018 generation projects are at or below

[60] Staff/701, Kaufman/33.
[61] Staff/701, Kaufman/33.
[62] Staff/701, Kaufman/34.

the current level. Staff also recommends that if PGE relies on generation project managers to complete competitively bid projects, the fully loaded cost of these project managers should be included in the bid for self-ownership.

Q. What do you recommend regarding the Eastside Biological Services Technician, Environmental Communication FTE?

A. PGE is requesting one FTE to repair corporate image in the Pelton-Round Butte region. PGE states in response to OPUC DR No. 626 part j that PGE's current monitoring of social channels indicate that it needs to provide counter-message regarding PGE's operations on the Deschutes river.[63] PGE claims that no legal expenses related to this issue are incorporated into the 2018 rate case.[64] Staff has not found evidence that PGE's operating costs are impacted by its poor image regarding the fish habitat on the Deschutes River. This FTE appears to be related to corporate image. Staff recommends excluding this FTE as an incremental FTE.

Q. What do you recommend regarding the Environmental Compliance and Licensing - Environmental Specialist?

A. PGE indicates in response to OPUC DR No. 626 part e that the number of FTE for Carty has not increased relative to current rates.[65] Staff recommends excluding this FTE as an incremental FTE.

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[63] Staff/701, Kaufman/34.
[64] Staff/701, Kaufman/34.
[65] Staff/701, Kaufman/32.

Q. What do you recommend regarding the Carty PSES -Compliance Specialist?

A. PGE indicates in response to OPUC DR 626 part e that the number of FTE for Carty has not increased relative to current rates.[66] Staff recommends excluding this FTE as an incremental FTE.

Q. Please recap Staff's investigation of and recommendations for O&M FTE.

A. PGE proposes adding 32 generation FTE. Staff asked detailed questions regarding 17 FTE. Of these, Staff only found that 3 FTE did not require either additional cost adjustments, or elimination from the 2018 revenue requirement. Staff recommends excluding expenses associated with 13 production O&M FTE and reducing consulting expense by $90,000. Generally, Staff's detailed investigation supports the labor adjustment proposed in Staff/400.

[66] Staff/701, Kaufman/32.

ISSUE 6: DECOUPLING

Q. Please summarize this issue and your recommended treatment.

A. PGE includes an estimate of the updates to the rates in PGE's decoupling tariff, Schedule 123.[67] The updates are consistent with past filings. Staff will review these values again once PGE has finalized them. PGE also proposed a small modification to the text of Schedule 123.[68] The change reduces the amount of revenue PGE recovers from new customers incremental to the number forecasted in the current rate case. Staff reviewed the workpapers underlying the proposed change and it appears reasonable. Staff recommends the Commission accept PGE's proposed changes to Schedule 123.

[67] PGE/1400, Cody - Macfarlane/27.
[68] PGE/1401, Cody - Macfarlane/50.

ISSUE 7: SECURITY LABOR

Q. Please summarize this issue and your recommended treatment.

A. PGE is requesting three additional FTE for physical security. PGE states that the need for these FTEs is driven by expanded footprint associated with Tucannon, Port Westward 2, and Carty. PGE is requesting one additional FTE to manage security planning related to Critical Infrastructure Protection regulation 014-1.[69] The plant expansions that PGE cites as driving the need for the three additional FTE have been in service for at least six months in 2016. There is no evidence that the 2016 staffing level is not sufficient. Staff recommends excluding the three additional security FTE from the calculation of PGE's revenue requirement. Staff does not propose an adjustment to the Critical Infrastructure Protection FTE.

[69] PGE/600, Lobdell – Tooman/8.

ISSUE 8: AFFILIATED INTERESTS

Q. Please summarize this issue and your recommended treatment.

A. PGE's opening testimony does not address affiliated interest issues. However, as part of this filing PGE does assign and allocate costs to affiliates.[70] Staff reviewed PGE's affiliated interest transactions and cost allocations. At this time, Staff has no adjustments to PGE's affiliated interest transactions or cost allocations. However, Staff is continuing to evaluate PGE's cost allocation of the World Trade Center costs, labor cost of operating affiliates, and overhead cost of operating affiliates.

Q. Please summarize your review of PGE's affiliated interests.

A. Staff reviewed the following items:

- Affiliate master services agreements
    - PGE maintains a single master services agreement under which it transacts with all its affiliates.
- Affiliate financial statements
    - Affiliate financial statements do not indicate abnormal earnings.
- Affiliate employees
    - Affiliates do not have any employees. PGE employees provide labor services to affiliates. Staff is continuing to evaluate this item.
- Affiliate transactions
    - 121 SW Salmon Corp bills PGE for rent of WTC.

[70] PGE/200, Tooman – Brown/20 at lines 11 to 17 discusses allocations to non-utility. This includes allocations to affiliates. PGE/202 also includes the revenue associated with the affiliate Salmon Springs Hospitality Group.

- o Salmon Springs Hospitality Group bills PGE for hospitality services.
- o PGE bills SSHG for labor, rent, and other services.
- o PGE bills PGE foundation for labor, rent, and other services.

- Labor loading rates
  - o PGE loads labor for pension costs, employee support, and incentives, paid time off, employee benefits, payroll tax, and injuries. Staff is continuing to investigate the costs included in the loading rate calculations. Staff will request follow-up data from PGE regarding how the hard-coded amounts to be loaded and labor base values are calculated in Attachment A to the response to OPUC DR 134.[71]
- WTC costs and cost allocations
  - o WTC costs include the costs of renting, maintaining, and operating WTC. These costs include a return component for PGE's capital invested in WTC. It is not clear what the basis for the allocation of WTC costs is. Staff recommends that PGE's cost allocation manual be updated to include a description of the factors used to allocate WTC costs. Staff is continuing to evaluate this item. Staff will request follow-up data from PGE regarding how the hard-coded allocation factors in Attachment B to the response to OPUC DR 134 are calculated.[72]

[71] *See* Staff/701, Kaufman/2.
[72] *See* Staff/701, Kaufman/2.

- Information technology allocations
  - o Staff is continuing to review the information technology allocation method. PGE's cost allocation manual appears to conflict with PGE's workpapers. The allocation manual indicates that "Some costs are allocated based on counts of equipment, some use historical analysis, and others use the results of the spread of all of the previous methods."[73] However, Staff's review of Attachment C to PGE's response to OPUC DR 134 indicates that PGE uses a single IT allocator, but that the allocator has a different basis not for the costs that are allocated, but rather for the groups that receive allocations. Staff will request follow-up data from PGE regarding how the model included in Attachment C of the response to OPUC DR 134 is consistent with PGE's allocation manual.[74]
- Production services allocations
  - o Production services allocations are based on historic usage of printing and mailing services. However, the allocation factors for 2016 and 2017 are identical. Staff is continuing to investigate the reason for this. Staff will request follow-up data from PGE regarding why these allocation factors have not changed from 2016 to 2017.
- Corporate helicopter allocations
  - o PGE's helicopter is allocated based on historic usage. Staff notes that from 2012 to 2015 the allocation factors are identical. In 2016

[73] Docket No. RE 64, PGE 2016 Affiliated Interest Report page 10.
[74] *See* Staff/701, Kaufman/2.

administrative use increased from the historic 12 percent to 39 percent. Staff is continuing to investigate the reason for the historic consistency and the recent change. Staff will request follow-up data from PGE regarding why these allocation factors experienced such large changes in 2016.[75]

In general, PGE appears to have a comprehensive accounting system for assigning, loading and allocating costs. Staff is continuing to review the responses and attachments PGE submitted in response to OPUC DRs 129 through 138, and particularly the response to OPUC DR 134.[76] Staff will report on the result of follow up discovery in Staff's reply testimony. Staff recommends PGE's treatment of affiliated interests and cost allocations as filed, subject to resolution of the concerns laid out in this section of Staff's testimony.

Q. Does this conclude your testimony?

A. Yes.

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[75] PGE Affiliated Interest Reports for 2012 to 2016.
[76] *See* Staff/701, Kaufman/2.

CASE: UE 319
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 701

Exhibits in Support
Of Opening Testimony

June 16, 2017

UE 319 Staff 701

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March 20, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 134
Dated March 6, 2017

Request:

Please refer to the PGE 2015 Affiliated Interest Report filed under Docket No. RE 64. Please provide the work papers supporting the following calculations:

a. **Labor loading rates on page 9;**
b. **WTC cost distribution on page 10;**
c. **WTC total cost pool on page 10;**
d. **World Trade Center Allocations on page 10;**
e. **Information Technology, Production Services, and Helicopter Allocations on page 11;**
f. **Corporate Governance Allocations on page 13;**
g. **Corporate Allocation Summary on page 14;**
h. **Other Utility Administrative Allocations on page 14; and**
i. **Stores loading rates on page 15.**

Response:

See Attachments 134-A through 134-G.

A. See Attachment 134-A - Labor loading rate work papers;

B. See Attachment 134-B– WTC cost distribution work papers;

C. There are no work papers for the WTC total cost pool detail. See Attachment 134-B.

D. There are no work papers for the World Trade Center Allocation detail. See Attachment 134-B.

E. See Attachment 134-C for work papers regarding Information Technology, Production Services, and Helicopter;

F. See Attachment 134-D for the Corporate Governance work papers;

G. See Attachment 134-E for the Corporate Allocation Summary work papers;

H. See Attachment 134-F for support for the Utility Administrative Allocations. This is represented by output from PowerPlan with brief descriptions of each allocation. The process is described in the Attached report that evaluated PGE's allocation methodology and also summarized in the Allocation Manual provided annually with PGE's Affiliated Interest Report.

Note: In Docket No. UE 294, PGE agreed to a third party review of its processes in capturing overhead construction costs. After its review, PricewaterhouseCoopers, LLP, determined that:

> "based on the work performed as described throughout this report, PGE's processes for capturing overhead construction costs and directly charging and indirectly allocating such costs to construction projects assign costs to construction work orders that are reasonable, supportable, operating as described and in compliance with the FERC USoA."

I. See Attachment 134-G for the Stores Loading work papers.

UE 319

Attachment 134-A

Provided in Electronic Format only

Work Papers

Labor Loadings

UE 319

Attachment 134-B

Provided in Electronic Format only

Work Papers

WTC Cost Distribution

WTC total Cost Pool and Allocations

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Attachment 134-C

Provided in Electronic Format only

Work Papers

for Information Technology, Production Services,
and Helicopter

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Attachment 134-D

Provided in Electronic Format only

Work Papers

Corporate Governance

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Attachment 134-E

Provided in Electronic Format only

Work Papers

Corporate Allocation Summary

UE 319

Attachment 134-F

Provided in Electronic Format only

Construction Overhead

UE 319

Attachment 134-G

Provided in Electronic Format only

Work Papers

Stores Loading

March 17, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 145
Dated March 6, 2017

Request:

Please provide a narrative describing PGE's project management process for the Carty generation project.

Response:

On March 16, 2017, OPUC Staff notified PGE that it withdraws its request in OPUC Data Request No. 145.

March 17, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 146
Dated March 6, 2017

Request:

Please provide all Carty project management documents.

Response:

On March 16, 2017, OPUC Staff notified PGE that it withdraws its request in OPUC Data Request No. 146.

March 17, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 147
Dated March 6, 2017

Request:

Please provide all construction contracts and agreements related to the Carty project.

Response:

On March 16, 2017, OPUC Staff notified PGE that it withdraws its request in OPUC Data Request No. 147.

March 17, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 148
Dated March 6, 2017

Request:

Please provide all change orders related to the Carty project.

Response:

On March 16, 2017, OPUC Staff notified PGE that it withdraws its request in OPUC Data Request No. 148.

March 17, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 149
Dated March 6, 2017

Request:

Please provide all email communications between PGE and Carty contractors.

Response:

On March 16, 2017, OPUC Staff notified PGE that it withdraws its request in OPUC Data Request No. 149.

March 17, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 150
Dated March 6, 2017

Request:

Please provide all PGE Board of Director and subcommittee presentations and meeting minutes related to the Carty project, including but not limited to the following:

a. **Request for proposal process;**
b. **Bid selection;**
c. **Design;**
d. **Construction;**
e. **Performance bonds;**
f. **Construction litigation; and**
g. **Rate recovery;**

Response:

On March 16, 2017, OPUC Staff notified PGE that it withdraws its request in OPUC Data Request No. 150.

March 17, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 151
Dated March 6, 2017

Request:

Please refer to PGE's 2016 10-k (Part II, Item 8, Note 17) which states "On December 18, 2015, the Company declared the Contractor in default under the Construction Agreement and terminated the Construction Agreement." Please explain when and how PGE determined that the referenced Contractor was in default.

Response:

On March 16, 2017, OPUC Staff notified PGE that it withdraws its request in OPUC Data Request No. 151.

March 17, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 152
Dated March 6, 2017

Request:

Please refer to UE 219/PGE/200, Tooman – Brown/17 which describes Carty related legal matters. Please identify all legal expenses associated with the referenced legal matters and explain PGE's treatment of these expenses in the current rate case.

Response:

PGE objects to this request on the basis that it is overly broad. Notwithstanding its objection, PGE replies as follows:

Attachment 152-A identifies legal expenses related to Carty legal matters, which can also be found in PGE's work papers submitted in OPUC Docket No. UE 319.[1] PGE incurred legal expenses in 2016 and has budgeted for additional legal expenses in 2017. Ultimately, PGE's budget for legal expenses in 2018 will depend on the timing of Carty legal matters that are described in PGE's 2016 10-K (Part II, Item 8, Note 17).

PGE's 2018 test year forecast does not include legal expenses specifically assigned to Carty. The Performance Bond between PGE and the sureties provides for the recovery of reasonable legal expenses by the prevailing party in litigation arising from or related to the Performance Bond. PGE's claims against the sureties include a claim to recover the reasonable legal costs incurred in the litigation arising from the Performance Bond.

[1] See the non-confidential work paper titled "Corporate Support Summary_2018_Final" in Exhibit 600.

UE 319

Attachment 152-A

Provided in Electronic Format only

Legal Expenses Related to Carty Legal Matters

April 7, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 362
Dated March 27, 2017

Request:

Please refer to UE 319 / PGE / 700, Jenkins – Rodehorst / 12. Please also refer to the file produced in response to Staff DR 157 "OPUC_DR_157_Attach A.xlsx".

a. **Please confirm that the amount credited to the major maintenance accrual account as collections from customers is equal to the amount approved in the Company's most recent general rate case.**
b. **Please explain why the amount credited to the major maintenance accrual account is not tied to actual customer bills or revenues.**
c. **Does PGE maintain any other deferral accounts that are credited by a fixed amount each year regardless of actual revenues? If yes please identify such deferrals.**

Response:

a. Please see Attachment 362-A for confirmation that the amount credited to the major maintenance accrual account as collection from customers is equal to the amount approved in PGE's 2016 general rate case (Docket No. UE 294) through Commission Order 15-356.
b. The reason is that Commission orders specifying amounts to collect in rates do not contain a true-up provision to actual customer bills or revenues.
c. Yes. PGE's rate base in UE 319 includes the following items that are amortized by fixed amounts:
   - CET deferrals from UE 262, UE 283, and UE 294;
   - IT deferral from UE 262;
   - Generation Plant Maintenance deferral from UE 197; and
   - Incentive Adjustment from UE 283.

UE 319

Attachment 362-A

Provided in Electronic Format only

Major Maintenance Accruals
Net Expenses 2016 vs Approved Expenses in UE 294

April 14, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 412
Dated March 31, 2017

Request:

Please refer to Attachment A to OPUC DR 412 which summarizes actual and forecasted values for PGE other revenues.

a. Please confirm the actual and forecasted values are correct.
b. Please provide the actual other revenue for 2009. Please include all other revenue that would be comparable to the 2009 forecasted values in the referenced attachment.
c. For each forecast that differs from actuals, please explain the source of the forecast error.
d. PGE appears to have under forecasted other revenues in every rate case of the last ten years. Has PGE made any adjustments to its other revenue forecasting methodology in UE 319 to account for the historic forecast error? If yes, please explain such changes. If no, why not?

Response:

a. Attachment 412-A provides a detail listing of the components of PGE's Other Revenue from 2006-2016 – see "Summary by Year" worksheet. The core data and adjustments used to derive these amounts are provided in the worksheets "Actuals vs Forecast 2006-2009" and "Actuals vs Forecast 2010-2016". Where test year forecasts were developed for general rate cases (GRC), we list those amounts; for years with no GRC, we list budget amounts. The referenced adjustments to actuals and budgets/forecasts are explained as follows:
   - Adjust 2010 actuals by approximately $5.1 million to remove oil resales. In all of PGE's annual Results of Operations Reports (ROO) and Power Cost Adjustment Mechanism (PCAM) filings, PGE reclassifies oil, gas, and transmission resales from Other Revenue to net variable power costs (NVPC). In 2010, this amount was similarly reclassified to NVPC in the ROO and PCAM. In short, oil resales are not appropriate to include in an analysis of Other Revenue for test year forecasting.
   - Adjust 2012 data for the following items:

- Reclassify amounts within Other Revenue to correct certain steam sales being posted to account 4560001 rather than account 4560012. This occurs in both actuals ($0.6 million) and forecast ($2.1 million), but has no impact on total Other Revenue (i.e., these adjustments net to zero).
- Adjust actual Other Revenue by approximately $82,000 to remove revenue associated with Large Generator Interconnection Procedures (LGIP). These revenues relate to studies PGE performed for third-party generation that could potentially deploy in PGE's control area (typically performed as part of PGE's integrated resource plan proceedings). Because the LGIP revenues and incremental expenses are effectively offsetting and since neither is budgeted by the operating departments, we remove the associated actual revenues from this analysis.

- Adjust actual 2013 Other Revenue by approximately $0.3 million to remove revenue associated with LGIP, as described above.
- Adjust actual 2014 Other Revenue by approximately $1.2 million representing the payment received from BPA for wind curtailment, which we remove for two reasons. First, approximately $0.4 million of this payment represents lost renewable energy certificates (RECs) that are reclassified from Other Revenue to NVPC in the 2014 PCAM and ROO. We do this because when RECs are sold, we record the benefit to NVPC similar to resales of gas, oil, and transmission, hence we reclassify this REC benefit to NVPC. Second, the remaining $0.8 million represents lost production tax credits (PTCs), which were already reflected in the test year forecast as a reduction to income taxes based on forecasted wind generation. In summary, because PGE had already included the benefit of wind generation in the 2016 test year forecast based on normal conditions and since this type of BPA payment would not be included in a test year forecast (in either NVPC or Other Revenue), we remove this payment from 2014 actuals.
- Revise the test year forecasts for regulatory adjustments applied during those GRCs and adopted by Commission orders to reflect those amounts in prices.

b. Attachment 412-A provides the requested 2009 information.

c. See Attachment 412-A and specifically, the worksheets that provide "Variance Comments" for 2010-2015. These years reflect significant variances of actual amounts over budget/forecast. Variance data from 2009 and prior were in PGE's old accounting system that we replaced in April 2011 and are no longer available (2010 and Q1, 2011 data are available because of PGE converted them to the new system although they are not fully comparable).

d. Other Revenue is derived from a number of diverse activities as performed by several different operations within PGE. Budgeting for these activities (or forecasting for two years out) is complicated by the fact that significant inputs are not available at the time the budgets/forecasts are prepared as evidenced by the information provided in response to part c, above. As such, PGE's budget/forecast represents the best information available at the time they are prepared.

UE 319

Attachment 412-A

Provided in Electronic Format only

Other Revenue 2006-2016

June 2, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 618
Dated May 18, 2017

Request:

Please refer to the file produced in response to OPUC DR 525 "Environmental Compliance and Licensing - Environmental Specialist.pdf".

a. **Please describe the work this position will perform related to Carty air quality.**
b. **Did the Carty 1 bid include ongoing labor costs associated with environmental compliance and licensing? If no, why not? If yes, please provide the related sections of the bid.**

Response:

a) Air quality services that will be performed by this position at Carty relate to:

- The various air quality reporting requirements in the Title V operating permit;
- Greenhouse gas (GHG) reporting requirements;
- Coordination and oversight of periodic source testing (stack testing); and
- Regular support for the continuous emissions monitoring systems (CEMS) program at Carty.

Carty (like other thermal plants) has an extensive CEMS program to monitor plant environmental performance and compliance. This role will additionally provide on-site training to Carty operations staff regarding air quality compliance obligations.

b) The Carty 1 bid did not address the ongoing labor costs for environmental compliance and licensing. These services are provided by PGE's Environmental and Licensing Services team, and the bid process did not include these services because these services are provided by the corporate environmental function, rather than plant-dedicated staff. The bid process required the contractor to address environmental compliance during the construction period (e.g., waste management, storm water runoff), but not after the plant was constructed and PGE took ownership.

June 2, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 619
Dated May 18, 2017

Request:

Please refer to the file produced in response to OPUC DR 525 "PSES -Compliance Specialist" which states "new generation plants and the ever-growing regulatory compliance landscape will require a new specialist position." Did the Carty 1 bid include labor costs associated with North American Electric Reliability Corporation and Western Electric Coordinating Council standard compliance? If no, why not? If yes, please provide the relevant sections of the bid.

Response:

The Carty 1 bid did not address costs associated with North American Electric Reliability and Western Electric Coordinating Council standard compliance. These services are provided by PGE's Power Supply Engineering Services (PSES) department and the bid did not include these services that are provided by the corporate PSES function, rather than plant-dedicated staff.

The "PSES-Compliance Specialist" is required in the PSES department for additional support to PGE's NERC and WECC compliance efforts due to the addition of Port Westward II, Tucannon River, and Carty generation plants between 2014 and 2016.

June 2, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 626
Dated May 18, 2017

Request:

Please refer to PGE/702.

a. **Regarding Energy Market Settlement Analyst, please explain what work will be performed on the settlement files. Please provide a sample settlement file and explain how often PGE will receive these files.**
b. **Regarding the Energy Market Policy Analyst**
   i. **Please identify each policy and rule change implemented by the Western Energy Imbalance Market (EIM) in 2017.**
   ii. **Please explain why a full FTE is devoted to monitoring EIM policy and rule changes.**
   iii. **Does PGE devote a full FTE to monitoring any other single program policy changes? If yes, identify these programs and provide the associated position description.**
c. **Regarding the Independent Spent Fuel Storage Installation Technician, please explain how the DOE cost reimbursements are accounted for in the Company's 2018 revenue requirement.**
d. **Regarding the Port Westward 2 Generation Technician:**
   i. **Please identify each instance in 2016 where having 5 operating crews would have reduced costs or maintenance issues at Port Westward 2.**
   ii. **The file provided in response to OPUC DR 525 named "PW2 - Generation Technicians.pdf" indicates that 100 percent of the cost increase will be offset by reduced overtime and contractor expenses.**

How are the reduced expenses associated with these FTEs incorporated into the 2018 revenue requirement?

e. **Regarding the Carty Generation Technician:**
   i. **Please explain why each gas plant needs its own planner scheduler.**
   ii. **Was the ongoing labor cost for a planner scheduler included in the Carty 1 bid? If yes, please provide the relevant sections of the bid.**

f. **Regarding the Power Supply Engineering Svcs Analyst:**
   i. **Please explain what the Reliability, Performance, and Monitoring Center is.**
   ii. **Please refer to the file produced in response to OPUC DR 525 named "PSES – Analyst.pdf". Please explain how the $350,000 in savings associated with this position are accounted for in the 2018 Revenue Requirement.**

g. **Regarding the Power Supply Engineering Svcs IT Analyst:**
   i. **Please identify the IT issues that occurred at Generation facilities in 2016 and provide the resolution time for each issue.**
   ii. **Please explain why a dedicated IT analyst will reduce the resolution time for Generation IT issues.**
   iii. **How are Generation IT issues currently addressed at PGE?**
   iv. **Will adding a dedicated generation IT analyst reduce the total labor hours spent on resolving generation IT issues? If no, why not?**

h. **Regarding the Power Supply Engineering Svcs Technical Writer Specialist:**
   i. **How does PGE currently develop and maintain generation procedures?**
   ii. **Has PGE's 2018 need to develop and maintain generation procedures changed relative to 2016? If yes, how?**

i. **Regarding the Generations Projects Project Manager:**
   i. **Please provide the number of active generation projects by year for 2013 through 2016.**
   ii. **How many active generation projects does PGE expect to have in 2018? How many of these projects relate to new wind or gas generation?**

j. **Regarding the Eastside Biological Services Technician, Environmental Communication:**
   i. **Does PGE have any other positions dedicated to single issue public relations? If yes identify such positions.**
   ii. **Please explain what costs associated with the Deschutes River Alliance lawsuit are included in the 2018 revenue requirement.**
   iii. **When does PGE anticipate that this lawsuit will be completed?**

iv. **How has PGE determined that current communication and public relations regarding Deschutes fisheries has not been sufficient?**

Response:

a) Regarding the Energy Market Settlement Analyst:

As described in PGE Exhibit 300, the Energy Market Analyst(s) – Settlements will be responsible for market operations strategies and settlement analysis. In PGE's Response to OPUC Data Request No. 467, PGE reported on the expected hire dates for these positions.

The CAISO settlement process is complex and data intensive. As shown in the CAISO payments calendar, PGE will be receiving data from CAISO on a daily basis. The CAISO payments calendar is available at:

http://www.caiso.com/Documents/CaliforniaISOPaymentsCalendar2017.xls

Essential job responsibilities for the analyst roles will include:

- Validating Charge Codes related to CAISO by utilizing various software tools.
- Validating settlement allocation for non-participating resources and Merchant load.
- Disputing discrepancies with CAISO for assigned charge codes.
- Validating charge allocations received from various EIM entities within the EIM.
- Providing consulting with Day-Ahead and Real-Time Operation on bidding strategy. This can include post trade-day analytics and an evaluation of plant and bidding performance.

Due to the voluminous nature of the data, PGE is not providing an entire settlement file. A sample of settlement data is included as Attachment 626-A. Note that Attachment 626-A contains "test" data and is not actual settlement data. It is also a small sample of the data PGE will process on a daily basis when it is participating in the Western EIM.

b) Regarding the Energy Market Policy Analyst:

The description provided in PGE Exhibit 702 is not a comprehensive description of the position. As described in PGE Exhibit 300, this position will be responsible for market operations strategies and regulatory policy as it relates to the merchant role in the market. In PGE's Response to OPUC Data Request No. 467, PGE reported on the expected hire date for this position. This analyst role will maintain generation resource data required by the CAISO for market participation. The analyst will also follow changes to Western EIM market rules and evaluate the impact on PGE, financially and operationally. Additionally, in cooperation with settlements analysts, the market analyst will evaluate plant and bidding performance via post trade-day analytics.

i. CAISO continually considers potential enhancements to the ISO market design, including the Western EIM (a part of the CAISO's real-time market). PGE is an active participant in CAISO stakeholder processes. A catalog of active CAISO stakeholder initiatives is available at:

http://www.caiso.com/Documents/StakeholderInitiativeMilestones.xlsx

ii. See the description at the beginning of PGE's response. PGE's description in Exhibit 702 is not a comprehensive description of the position. Furthermore, OPUC Staff's interpretation (implied in its question) of a single program appears to be too narrow. EIM is not a program, it is a market. PGE's participation in policy formation and rule changes that may impact this market may occur in multiple venues (e.g., CAISO, FERC, and BPA). This position will assist in formulating PGE positions that seek to establish market rules that benefit PGE's customers.

iii. Please see PGE's response to part (ii) above.

c) Regarding the Trojan ISFSI Technician:

The Department of Energy (DOE) cost reimbursements related to Trojan have not been added in the 2018 test year revenue requirement calculations.

The concept of recording refunds in advance of receiving the funds from DOE falls under the gain contingency rules. The standard of recognition of a gain contingency is: "substantially all uncertainties about the timing and amount of gain contingencies should be resolved before being recognized"

PGE's position is that the Determination Letter, once executed, is sufficient evidence that substantially all uncertainties have been resolved and the gain contingency can be recognized. The Determination Letter is negotiated late in the process, usually in November during the last couple of years.

DOE refunds are recorded in the Schedule 143 (Spent fuel) regulatory liability. Please see PGE's response to ICNU Data Request No. 097 for DOE refunds recorded in Schedule 143.

d) Regarding the Port Westward Generation technician:

i. PGE objects to this request on the grounds that it calls for speculation.

ii. When comparing 2016 actuals to 2018 forecast there is no decrease in overtime and contractor labor expenses because of the significant O&M savings at Port Westward 1 (PW1) during the 2016 planned outage. The scope and timing of the outage changed primarily due to having to swap out the turbine rotor as it was damaged in 2015 and this was capital work rather than O&M. However, when comparing 2017 O&M budget to 2018 forecast there is a reduction of $250,000 in overtime and contractor expenses by having five operating crews at PW1 and

PW2. Attachment 626-B provides the calculation of the reduction in PW1 and PW2 overtime and contract labor from the 2017 budget to 2018 forecast.

e) Regarding the Carty Generation Technician:

i. A planner scheduler is required at each generation plant to plan and schedule maintenance activities at the plant. Planning the maintenance work is a first critical step to ensure all maintenance jobs are completed in a safely manner. The planning also includes efficiency enhancements by ensuring that when maintenance jobs are stated, all parts and any specialty tooling is in site and staged to complete the work.

ii. PGE's labor requirements forecast for the Carty Generating Station were based on the known staffing requirements for PGE's Port Westward plant. PGE included this forecast as part of its 2016 test year forecast in Docket No. UE 294, which was subsequently approved by Commission Order No. 14-059. This forecast included 22.7 FTEs at Carty, but two of the FTEs were transfers, resulting in effectively 21 incremental FTE increase in line with the assumptions serving as the basis in the O&M labor costs as part of the Carty RFP. Attachment 626-C provides PGE's response to OPUC Data Request No. 317 in Docket No. UE 294 with a detailed explanation regarding Carty FTEs in PGE's 2016 test year revenue requirement. The FTE in question has been working in the planner schedule function at Carty since August 2016.

f) Regarding the PSES Svcs Analyst:

i. The Reliability, Performance, and Monitoring (RPM) center supports the Generation, Reliability and Maintenance (RME) program to improve PGE's maintenance practices that directly impact the operation of our generation resources. The RME program was discussed extensively in PGE's 2016 general rate case docketed under Docket No. UE 294, PGE Exhibit 700. Attachment 626-D provides the relevant pages from PGE Exhibit 700/UE 294 explaining the activities performed by the RPM center in support of the RME program.

ii. The $350,000 cost reduction mentioned in the "PSES-Analyst.pdf" document was an estimate at the time the position request form was developed and was not at PGE share. In actuality, the PSES budget was reduced in 2017 by approximately $260,000 as result of bringing in-house the plant performance monitoring previously provided by General Electric (GE). Attachment 626-E provides the 2017 Accounting O&M Adjustment request reflecting the GE costs that were eliminated in the 2017 PSES budget and reflected in the calculation of the 2018 Revenue Requirement as a reduction to PSES Outside Services expenses.

g) Regarding the PSES IT Analyst:

PGE inadvertently included this FTE in two different departments. An FTE that performs the same functions as the PSES IT Analyst was added in PGE RC 778, IT Business Relationship Management (IT BRM) T&D and Generation support as a Technical Specialist IV. For more details about the IT BRM Technical Specialist IV please see PGE Exhibit 502, page 2, PGE's response to OPUC Data Request No. 484, Attachment 484-A, and PGE's response to OPUC Data Request No. 509.

i. Attachment 626-F identifies IT issues at generation facilities in 2016 and their resolution time.

ii. The IT BRM Technical Specialist IV would work to reduce the time it currently takes to resolve IT issues. For instance, Attachment 626-F shows IN10075604, a Carty Wi-Fi issue, with an extended resolution time. This position would help analyze the issue and follow up with the resources to make sure that the appropriate resources were diligently working on their issues and escalating within IT if that wasn't the case. They would also understand the business systems so that they would be the first line of support if there was a question or issue.

iii. Currently, IT issues are reported to the service desk, which dispatches resources based on priority and availability. There is no IT liaison to the business to ensure that their issues are being resolved so they will provide better support.

iv. This resource will reduce the time spent resolving generation issues by ensuring that a dedicated resource that understands generation systems and the IT issue resolution process is available.

h) Regarding the PGE Technical Writer Specialist:

i. Generation Fleet Procedures are being developed using US Department of Energy templates and best practices from PGE generation plants. Going forward, PGE anticipates the technical writer will add five to ten new Generation Fleet Procedures each year. Each procedure has a Lead who is responsible for coordinating the work to maintain the procedure after it has been issued. PGE recently developed 75 common Generation Fleet Procedures that are used by our generation plants.

ii. Yes, prior to 2016, each generation plant had a unique set of procedures. In 2016, PGE developed the common Generation Fleet Procedure and an associated SharePoint site and began rolling procedures out. The new set of Generation Fleet Procedures are housed and maintained in the SharePoint site. Each procedure is reviewed periodically, updated and procedure review comments are collected daily on a SharePoint log where they are addressed by subject matter experts. Procedure forms are updated several times a year to incorporate new work best practices.

i) Regarding the Generations Project Manager:

i. The number of generation projects worked on by the Generation Projects group from 2013 through 2016 is:

1. 2013: Six generation projects,
2. 2014: Six generation projects,
3. 2015: Ten generation projects,
4. 2016: Ten generation projects.

ii. The number of known generation projects that the Generation Projects group is expecting to work on in 2018 is seven. None of the seven projects are related to new wind or gas generation as the Integrated Resource Plan (IRP) is still in progress. Based on past experience of emergent work, the currently known projects for 2018 are likely a fraction of the number that will actually be worked. The Generation Projects group will continue to support the IRP, review qualifying facility applications, and evaluate technologies for pumped storage, geothermal, landfill gas, and other emerging technologies.

j) Regarding the Eastside Biological Services Technician, Environmental Communication:

i. PGE has a centralized communications team in Portland that shares communications efforts on various issues such as safety, energy efficiency, customer programs, environmental issues, etc. Given the remote location, having a dedicated outreach resource allows us to be a better community partner in the region. Considering the outreach person will need to have technical expertise in natural resource issues is also a driver for this position.

While the need for this position was brought to light by the DRA litigation, it is not wholly dedicated to this issue. This position also supports safety, energy, and habitat education as required by our Pelton-Round Butte Water Quality Certificate and Water Quality Management and Monitoring Plan FERC license:

- Working with schools and business organizations this position arranges and conducts tours and provides education materials.
- Coordinating and staffing public events and fairs with messages about safety and habitat

ii. No costs associated with the DRA lawsuit were projected in the 2018 revenue requirements as planning for the litigation had not begun.

iii. It is difficult to determine litigation timelines due to its variable nature, but a reasonable estimate for federal court litigation is two years.

iv. PGE conducted a survey in January 2017 of 700 customers and Deschutes area residents, through DHM Research. The survey results indicated that PGE's outreach efforts were not sufficient. In addition, PGE received specific feedback from the Pelton Round Butte Fish Committee and signatory NGOs reflecting that current outreach efforts were not sufficient. As we monitored social channels, it was clear that additional work needed to be done to provide a counter-message to common misperceptions about the impact of PGE's operation on the river. Our opposition is very active and to continue to maintain our positioning, we need to be equally active, and this position plays a significant role in that effort.

UE 319

Attachment 626-A

Provided in Electronic Format only

Western EIM Settlement Sample

UE 319

Attachment 626-B

Provided in Electronic Format only

Port Westward 1 and Port Westward 2
Overtime and Contract Labor Reductions
2018 forecast vs 2017 budget

UE 319

Attachment 626-C

Provided in Electronic Format only

Docket No. UE 294
PGE's Response OPUC DR 317 – Carty FTE Count

UE 319

Attachment 626-D

Provided in Electronic Format only

UE 294 / PGE Exhibit 700
RPM Center Description

UE 319

Attachment 626-E

Provided in Electronic Format only

2017 O&M Adjustment
GE Smart Signal Cost Reductions

UE 319

Attachment 626-F

Provided in Electronic Format only

2016 IT Issues Resolution Times

May 5, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 525
Dated April 24, 2017

Request:

Please provide any studies or workpapers supporting the reason for the increase from Base Year 2016 to Test Year 2018:

a. **In FTEs at Port Westward and Beaver as described on PGE/700, Jenkins – Rodehorst/10 (lines 8-12); and**
b. **From four to five operating crews at Port Westward as described in PGE/702, Jenkins –Rodehorst/ 1.**
c. **Please explain the difference between FTE Delta between 2016-18 for FTEs in Generating Divisions reported in PGE/401, Merserau-Jaramillo/1, which is 51.5, and the 32 incremental FTEs listed in PGE/702, Jenkins-Rodehorst.**
d. **In FTEs in "GENERATING – OTHER Total" as shown on PGE/401, Mersereau – Jaramillo/1.**

Response:

a) Attachment 525-A provides the position request forms for the Port Westward 2 (PW2) FTEs described in PGE Exhibit 700, page 8, lines 8-12.

The addition of three FTEs at Beaver appears to be an increase from 2016 to 2018 because in 2016 PGE contracted for the work these positions would have completed.

As previously stated in PGE Exhibit 702, the increase in FTEs at Beaver is required to reduce overtime labor and is partially offset by savings from this reduction. Attachment 525-B provides the reduction in Beaver overtime labor in 2018 compared to 2016.

b) Please see Attachment 525-A for details regarding PGE's need to increase from four to five operating crews at PW2.

c) There is no difference. PGE Exhibit 702 references 32 FTEs and the net increase for Generation FTEs as listed in cell K612 of PGE Exhibit 401 is also 32. The gross increase of 51 Generation FTEs is reduced by PGE's unfilled position adjustment of 20 FTEs as described in PGE Exhibit 400, page 16, lines 19-22.

d) Attachment 525-C provides the "Generating-Other Total" position request forms making up the total request after adjusting for unfilled positions.

UE 319

Attachment 525-A

Provided in Electronic Format only

PW2 Position Request Forms

UE 319

Attachment 525-B

Provided in Electronic Format only

Beaver Overtime Labor Reduction

UE 319

Attachment 525-C

Provided in Electronic Format only

“Generating-Other Total” Position Request Forms

Stefan Cristea

From:	Mike Dwyer
Sent:	Thursday, September 22, 2016 11:06 AM
To:	Corporate Planning
Cc:	Spenser Williams
Subject:	Dept. 86 2018 Test Year New Position Request

Please assure that all your comments have been entered into the appropriate fields. If you have any questions or need further assistance, please contact your Corporate Planning Analyst.

2018 Test Year
New Position Request

Department: 86

Manager: Michael Dwyer

Dept. Title: Port Westward

Corporate Planning Analyst: Spenser Williams (Generation)

Position Title: Technician II (2 positions over 2016 authorized, filling first in 2017)

Annual Salary: $88,691

Work Percent: 100

Default Labor Account: 16400-086-5480001-7000001977

1. Provide a short position description

TWO additional technicians with immediate hiring to support progression to 5 operating crews and PW2 maintenance.

2. Why is this position needed; what has changed in your department that drives the need for a new position?

The maintenance requirements for PW2 were underestimated. Not counting work which is now being accomplished on shift by the 3-man operating crews, there are 4-5 man-years of work. This also does not count future major interval maintenance, currently expected in 2019 and beyond, which is expected to be performed with contractor assistance.

3. Are there any cost reductions to offset this new position?

Overtime labor costs should fully offset costs of these positions. Overtime reduction results when we move to 5 operating crews from current 4 crews due to much less OT to cover PTO. Adding two positions for a total of 20 technicians allows 5 crews of three for no additional net cost. First position requested for 2017 will be offset by reduced PW2 contractor maintenance. Having the additional positions also allows reducing the use of contractors during PW1 annual outages.

4. Describe other options considered (Cross-trainer, temporary contractor, reallocation of work, etc.)

Contract labor evaluated for maintenance but engine maintenance is increasing significantly and predicted to be spread throughout the year. Work has already been reallocated to operating crews to the extent practical..

5. Other Comments

The goal is to increase total number of union technicians to 20 from the current 18. This allows five three-man crews of operating technicians so that the relief crew can handle most PTO associated with operations with straight time. Having a five-man maintenance staff should allow completion of all expected routine preventive and corrective maintenance up to the 8000 hour engine inspections. If the 5 technicians on maintenance are successful, there will be no net increase in cost.

For Corporate Planning Use Only:

Officer Signature: **Date:**

CASE: UE 319
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 702

Exhibits in Support
Of Opening Testimony

June 16, 2017

This exhibit is confidential and

Is subject to Protective Order No.17-057

CASE: UE 319
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 703

Exhibits in Support
Of Opening Testimony

June 16, 2017

Local Climate Analysis Tool Hinge Fit Model Trend

	December	January
PDX Airport	-0.009	0.087
KGW-TV	0.004	0.102
Beaverton	-0.002	0.105
Troutdale	-0.001	0.100
Average	-0.002	0.099
Maximum	0.004	0.105
Minimum	-0.009	0.087
Range	0.013	0.018
Range as PCT of Average	-6.625	0.183

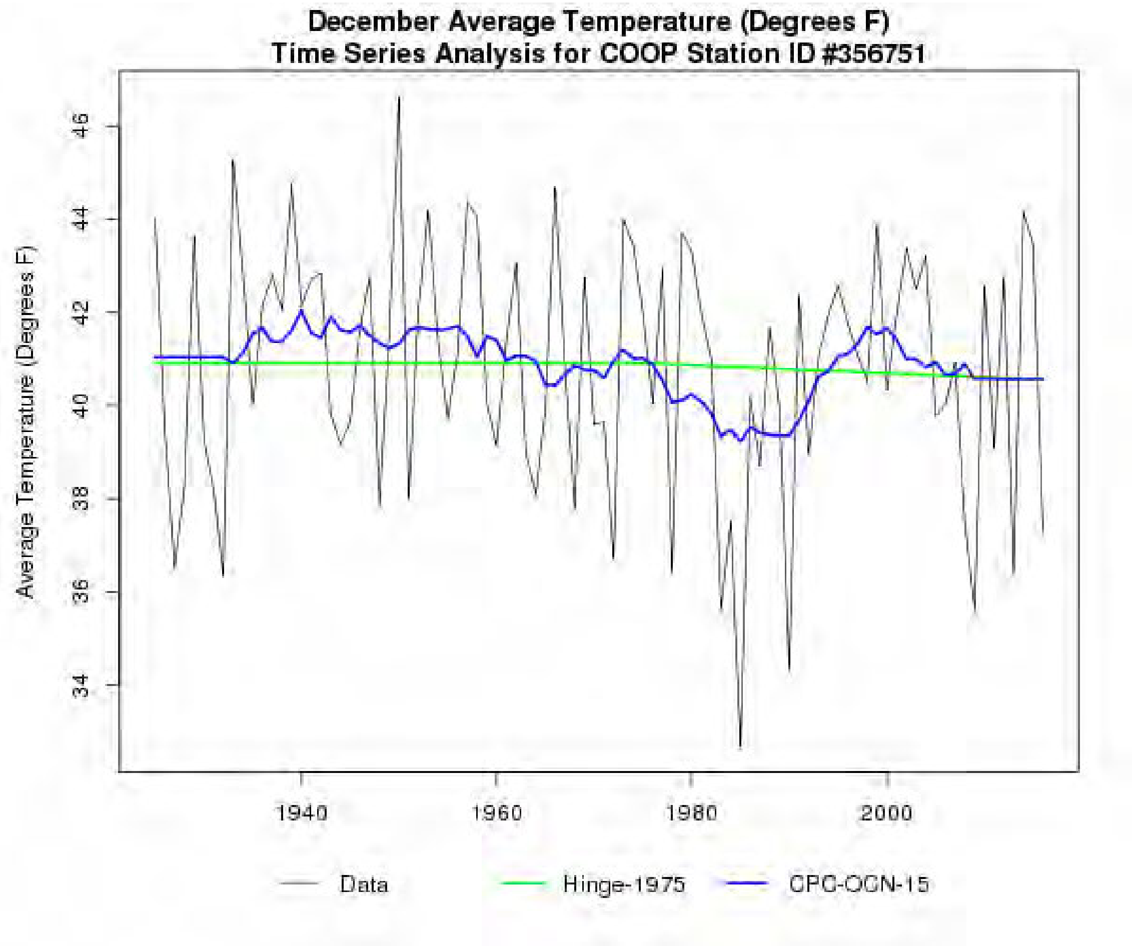
	PDX Airport Trend
Dec-16	-0.009
Dec-15	-0.015
Dec-14	-0.024

LCAT-1194-1497025980_6932 Generated at: 06-09-2017 16:33:01 UTC

LCAT
- Local Climate Analysis Tool -

LCAT-1194-1497025980_6932

Generated Images



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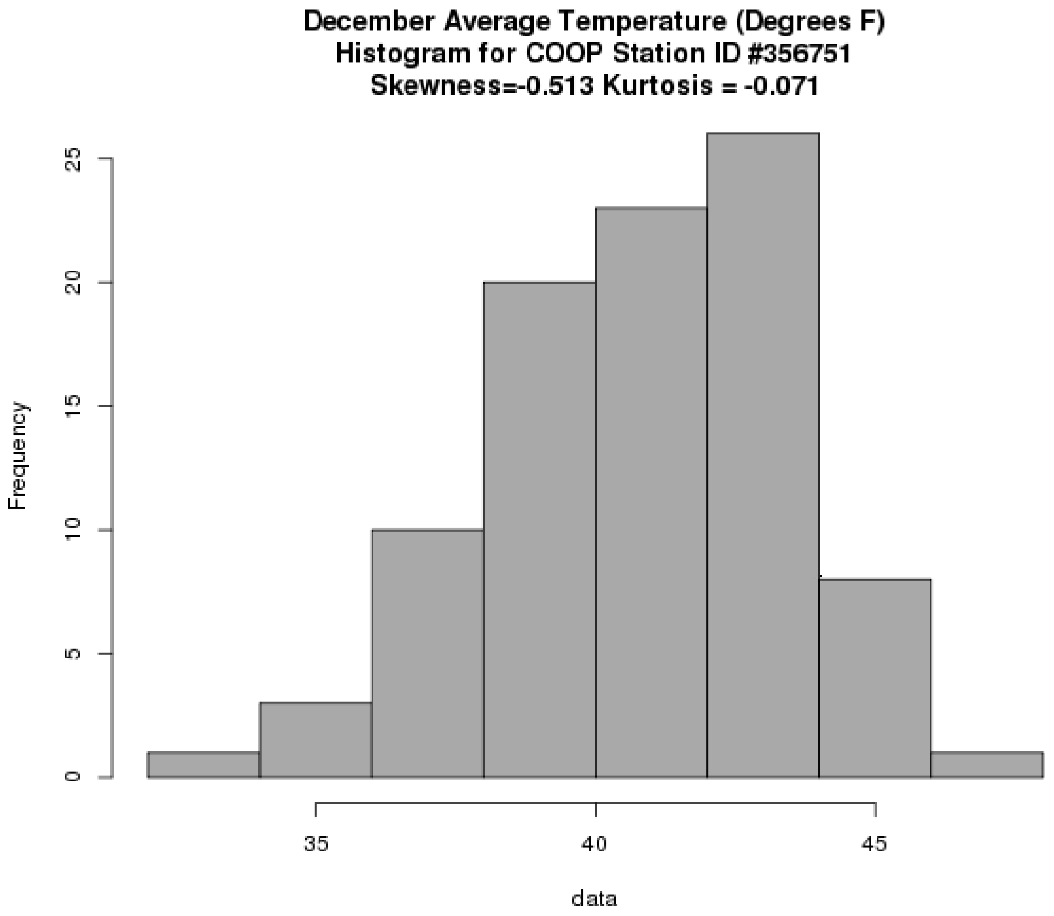
LCAT
- Local Climate Analysis Tool -



L C A T
- Local Climate Analysis Tool -

Statistics

Data	Statistics
Mean	40.81
Median	41.11
Mode	35.64
Minimum	32.70
Maximum	46.63
Standard Deviation	2.660
Skewness	-0.513
Kurtosis	-0.071

Trend Types Selected:

Hinge (1975)

OCN (15yr)

Trend Performance

Root Mean Square Error

Hinge-1975:2.75 Degrees_F

CPC-OCN-15:2.79 Degrees_F

LCAT-1194-1497025980_6932 Generated at: 06-09-2017 16:33:01 UTC

LCAT
- Local Climate Analysis Tool -

Metadata

Data Set:Homogenized Station Data

Variable: Average Temperature (degrees F)

Station Identifier Tag:356751

Station Metadata:PORTLAND INTL AP

WFO:PQR

Lat/Lon/Elev:45.59580000/-122.60930000/19.00000000 feet

County:MULTNOMAH

Request

Analysis Type:

Hinge (1975)

OCN (15yr)

Analysis Type:

Signal Index:Oceanic Niño Index (ONI)

Signal Phases:Negative/Positive

Signal Threshold Type:Critical Value (Index)

Reference Period:1961 - 1990

Time Scale:Monthly

Time Period:December

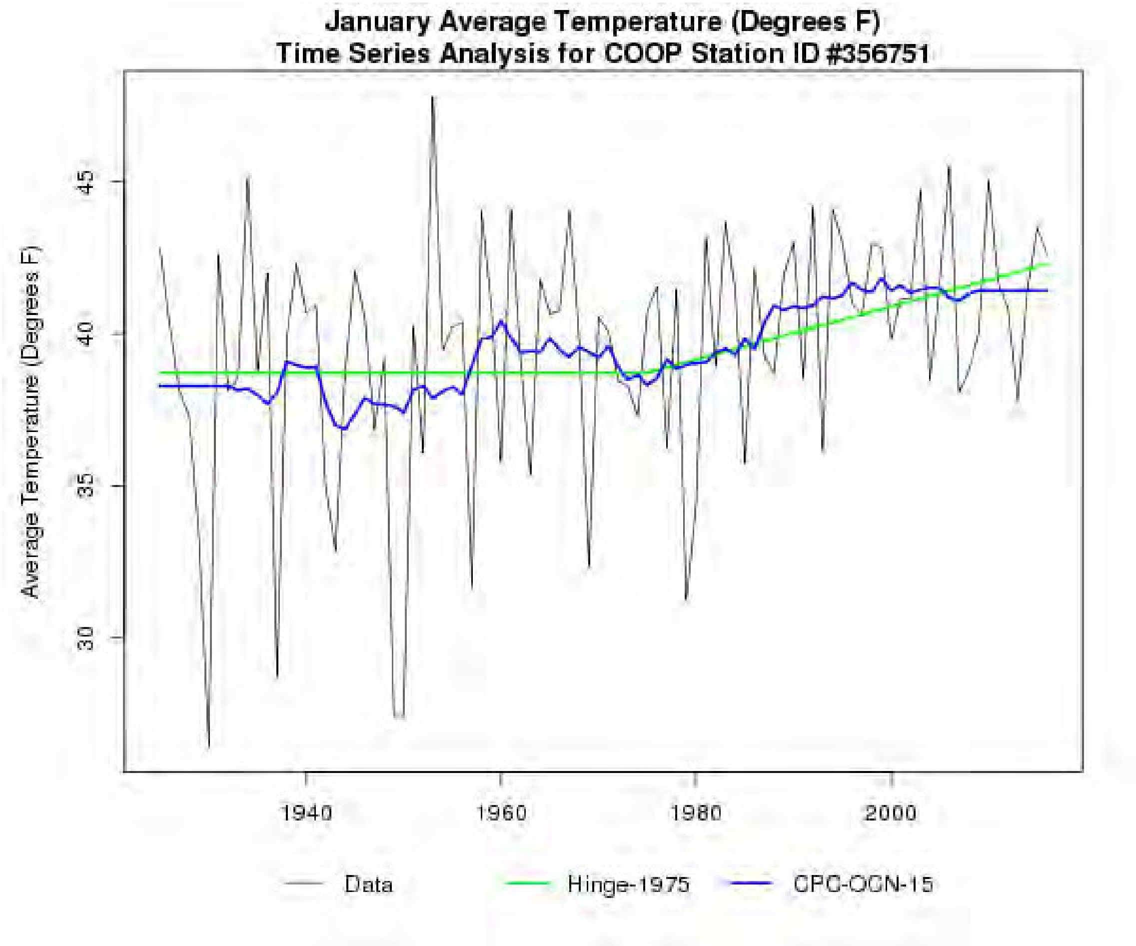
Time Range:1925 - 2016

LCAT-1194-1497026029_2519 Generated at: 06-09-2017 16:33:50 UTC

LCAT
- Local Climate Analysis Tool -

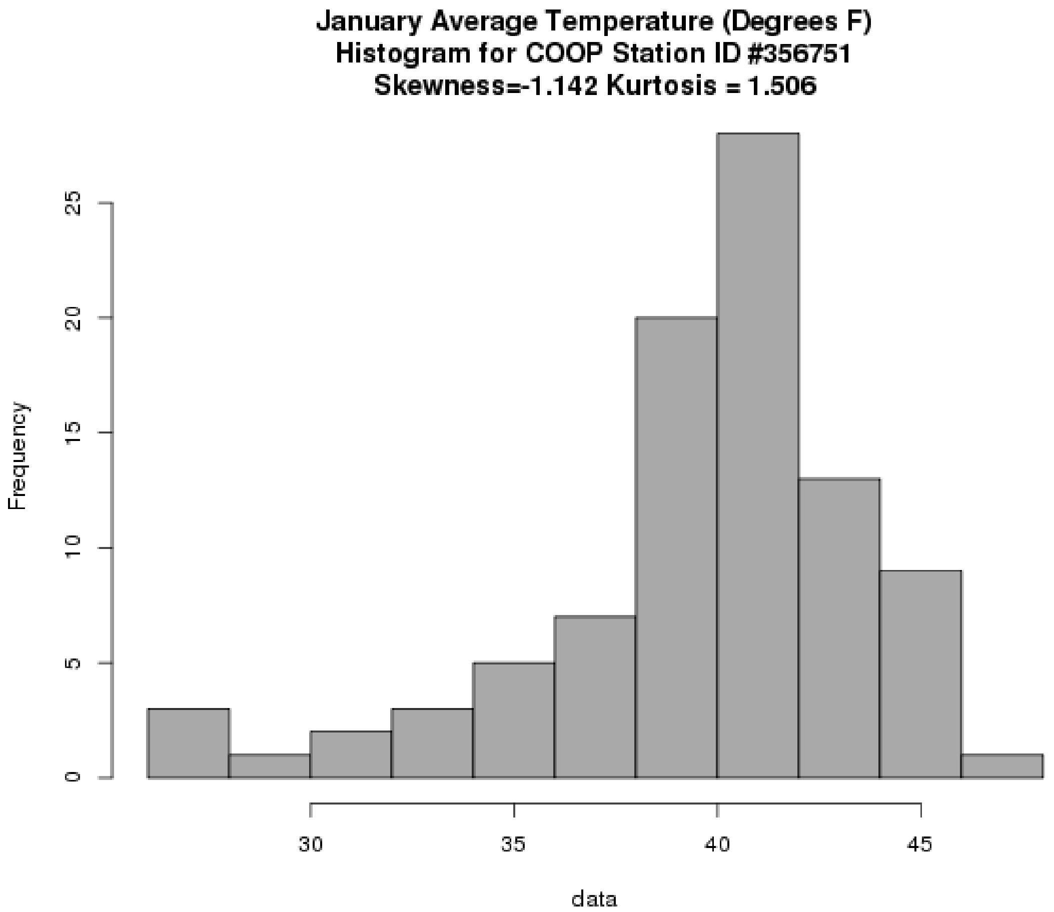
LCAT-1194-1497026029_2519

Generated Images



LCAT-1194-1497026029_2519 Generated at: 06-09-2017 16:33:50 UTC

L C A T
- Local Climate Analysis Tool -



LCAT-1194-1497026029_2519 Generated at: 06-09-2017 16:33:50 UTC

LCAT - Local Climate Analysis Tool -

Statistics

Data	Statistics
Mean	39.51
Median	40.33
Mode	38.55
Minimum	26.46
Maximum	47.80
Standard Deviation	4.074
Skewness	-1.142
Kurtosis	1.506

Trend Types Selected:

Hinge (1975)

OCN (15yr)

Trend Performance

Root Mean Square Error

Hinge-1975:2.46 Degrees_F

CPC-OCN-15:2.43 Degrees_F

LCAT-1194-1497026029_2519 Generated at: 06-09-2017 16:33:50 UTC

LCAT
- Local Climate Analysis Tool -

Metadata

Data Set:Homogenized Station Data

Variable: Average Temperature (degrees F)

Station Identifier Tag:356751

Station Metadata:PORTLAND INTL AP

WFO:PQR

Lat/Lon/Elev:45.59580000/-122.60930000/19.00000000 feet

County:MULTNOMAH

Request

Analysis Type:

Hinge (1975)

OCN (15yr)

Analysis Type:

Signal Index:Oceanic Niño Index (ONI)

Signal Phases:Negative/Positive

Signal Threshold Type:Critical Value (Index)

Reference Period:1961 - 1990

Time Scale:Monthly

Time Period:January

Time Range:1925 - 2016

CASE: UE 319
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 704

Exhibits in Support
Of Opening Testimony

June 16, 2017

Comparison of Staff and PGE forecast

Use per Customer (kWh)	PGE 2018	Staff 2018	Staff Adjustment
Single-Family Heat	14,119	14,337	218
Single-Family Non-Heat	9,873	10,082	209
Multiple-Family Heat	7,804	7,977	174
Multiple-Family Non-Heat	5,872	5,969	97
Mobile Home Heat	13,497	13,502	5
Mobile Home Non-Heat	10,294	10,619	325
Other	10,472	10,561	90
Average Use per Customer	9,793		
Ultimate Deliveries (million of kWh)			
Single-Family Heat	1,568	1,593	24
Single-Family Non-Heat	3,628	3,705	77
Multiple-Family Heat	1,499	1,532	33
Multiple-Family Non-Heat	367	373	6
Mobile Home Heat	407	407	0
Mobile Home Non-Heat	40	41	1
Other	51	51	0
Schedule 7 Deliveries	7,560	7,702	142

ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2018

CATEGORY	RATE SCHEDULE	Forecast SDEC16E18 CUSTOMERS	Staff MWH SALES	TOTAL ELECTRIC BILLS PGE FORECAST w/ Sch. 125, 122, 146	TOTAL ELECTRIC BILLS STAFF FORECAST w/ Sch. 125, 122, 146	Change AMOUNT	Change PCT.
Residential	7	772,009	7,702,338	$922,614,324	$938,159,316	$15,544,991	1.7%

Staff Forecast

	Single-Family Heat	Single-Family Non-Heat	Multiple-Family Heat	Multiple-Family Non-Heat	Mobile Home Heat	Mobile Home Non-Heat	Other
1/1/2018	1,834	1,064	1,054	662	1,798	1,326	1,255
2/1/2018	1,594	916	932	588	1,566	1,161	1,104
3/1/2018	1,419	854	820	539	1,363	1,032	1,000
4/1/2018	1,202	775	682	475	1,129	874	856
5/1/2018	1,008	726	564	430	915	738	751
6/1/2018	915	744	503	425	808	679	717
7/1/2018	904	813	474	444	802	683	740
8/1/2018	932	878	473	471	829	716	776
9/1/2018	910	832	476	462	804	690	761
10/1/2018	879	720	470	412	795	667	696
11/1/2018	1,134	783	618	460	1,096	861	808
12/1/2018	1,606	977	911	601	1,598	1,194	1,098
Annual	14,337	10,082	7,977	5,969	13,502	10,619	10,561

CASE: UE 319
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 705

Exhibits in Support
Of Opening Testimony

June 16, 2017

Historic PGE Other Revenue Forecast Error

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Average
Actual Other Revenue	$ 17,263,169	$ 18,690,500	$ 20,557,924	$ 20,488,015	$ 26,151,397	$ 22,206,953	$ 24,696,544	$ 24,858,725	$ 27,626,038	$ 26,962,722	$ 26,720,329	
UE 197 Forecast			$ 17,817,205	$ 19,345,671								
UE 215 Forecast				$ 20,212,577	$ 19,911,732	$ 20,961,407						
UE 262 Forecast								$ 22,952,390	$ 21,395,720			
UE 283 Forecast									$ 22,563,005	$ 23,520,622		
UE 294 Forecast										$ 24,998,363	$ 25,138,408	
Year Ahead Forecast Error			$ (2,740,719)	$ (1,142,344)	$ (6,239,665)				$ (5,063,033)	$ (1,964,359)		$ (3,430,024)
Test Year Forecast Error				$ (275,438)		$ (1,245,546)		$ (1,906,335)	$ (6,230,318)	$ (3,442,100)	$ (1,581,921)	$ (2,446,943)
											Adjustment	(2,893,798)

PGE Other Revenue Forecast Variance Comments From Response to DR 412

Year	Revenue Source	Variance	Variance Explanation
2010	RentFrElecProperty-Joint Pole	$836,756	Revenue variance was related to wireless activity. PGE brought a lot of sites on-line in 2010 at activity levels that were much higher than anticipated. This led to significantly more make-ready revenue than was budgeted, as well as an increase in wireless rent. PGE was not privy to licensee forecasts for wireless, so we had no basis to forecast at that level.
2010	TransRevOthers-Intertie	$258,048	Actual revenues exceeded budget due to higher non-firm and short-term firm transmission sales than expected.
2010	Offsetting variances	($2,561)	
2011	RentFrElecProperty-Joint Pole	$436,564	Revenue variance was related to additional wireless activity, leading to more make-ready revenue than was budgeted, as well as an increase in wireless rent. PGE was not privy to licensee forecasts for wireless, so we had no basis to forecast at that level.
2011	Other Electric Revenues	$998,590	Expected revenues for the Energy Trust Energy Efficiency Contract are based on estimates that come from the Energy Trust of Oregon (ETO). In addition, the final expected revenues per the contract amendments with the ETO are not completed until the month prior to the new year; thus the 2011 increase in revenues was not determined and signed off on by the ETO until the end of 2010. The 2011 revenue budget, however, was estimated in mid 2010.
2011	Offsetting variances	($189,608)	
2012	Forefeited Discounts	$387,422	2012 is the first full year with AMI in place and the preferred billing cycle benefit available for customers. The forecast was a projected increase based on the estimated impact from AMI.
2012	RentFrElecProperty-Joint Pole*	$943,582	In 2012, attachment activity throughout the year picked up considerably (which was not projected at time of budget). This led to significantly more make-ready revenue than was budgeted, as well as an increase in pole attachment rental revenue.
2012	OthElecRev-SSHG	$229,099	PGE does not budget Salmon Springs Hospitality in Other Revenue but does include it in test year forecasts as an adjusting item.
2012	TransRevOthers-Non-Intertie	$179,276	ESS revenues exceeded projections because the direct access window was in November 2011 whereas the 2012 budget was developed in mid-2011.
2012	TransRevOthers-Intertie	$188,152	Actual revenues exceeded budget due to higher non-firm and short-term firm transmission sales than expected.
2012	Offsetting variances	$50,470	

PGE Other Revenue Forecast Variance Comments From Response to DR 412

Year	Revenue Source	Variance	Variance Explanation
2013	Other Electric Revenues	$386,156	Expected revenues for the Energy Trust Energy Efficiency Contract are based on estimates that come from the Energy Trust of Oregon (ETO). In addition, the final expected revenues per the contract amendments with the ETO are not completed until the month prior to the new year; thus the 2013 increase in revenues was not determined and signed off on by the ETO until the end of 2012. The 2013 revenue budget, however, was estimated in mid 2012. Recreation area visitation and subsequent revenue is very dependent on weather, which can result in revenues being higher or lower than budgeted based on: 1) Variations in summer weather, and 2) winter snows and potential slow melt may affect the opening of PGE's higher elevation sites near Timonthy Lake. In 2013, this uncertainty resulted in a Park Revenues exceeding budget by $157k
2013	OthElecRev-Steam Sales	$389,272	In 2013, Collins Lumber brought on their second kiln ahead of schedule, combined with Columbia River's Whey plant surpassing demand expectations drove revenues beyond budget.
2013	TransRevOthers-Non-Intertie	$401,385	ESS revenues exceeded projections because the direct access window was in November 2012 whereas the 2013 budget was developed in mid-2012.
2013	TransRevOthers-Intertie	$483,767	Actual revenues exceeded budget due to higher non-firm and short-term firm transmission sales than expected.
2013	Offsetting variances	($19,255)	
2014	RentFrElecProperty-Joint Pole*	$893,767	For 2014 and 2015 forecasting, PGE based anticipated pole attachment rent on certain licensees receiving the reduced rental rate (RRR). This was based on their historical RRR status as well as projections that we had with regard to their status at the time of forecasting. Some of PGE's largest licensees did not end up qualifying for the reduced rate in both 2014 and 2015, resulting in them paying between $1.50 to $1.75 more per attachment than initially forecast. PGE is not privy to licensee forecasts for wireless activity and typically cannot anticipate activity increases until they start occurring. Due to technological improvements, wireless activity has significantly increased over the last few years, especially during 2014-2015. In addition to new wireless sites in the years in question (and the resulting make-ready revenue), modifications to existing sites resulted in higher annual rental amounts collected, and higher rental escalations for subsequent years than anticipated.

PGE Other Revenue Forecast Variance Comments From Response to DR 412

Year	Revenue Source	Variance	Variance Explanation
2014	Other Electric Revenues	$831,404	Energy Trust Energy Efficiency Contract ($625k) - The expected revenues are based on estimates that come from the Energy Trust of Oregon. In addition, the final expected revenues per the contract ammendments with Energy Trust and not completed until the month prior to the new year; thus the 2014 expected revenues were not determined and signed off on by the ETO until the end of 2013. The revenue for the 2014 test year forecast, however, was estimated in late 2012. At the end of 2013 when the ETO provided their final expected revenues in the contract ammendment for 2014, the expected revenues were significantly higher than estimated when the 2014 forecast was being developed in late 2012. Park Revenues ($220k) - Recreation area visitation and subsequent revenue is very dependent on weather. The summers of 2014 and 2015 set attendance records for several recreation areas around the state, due to record setting temperatures that drew visitors to water based parks and campgrounds. Ultimately, revenues can be higher or lower than budgeted based on: 1) Variations in summer weather, and 2) winter snows and potential slow melt may affect the opening of PGE's higher elevation sites near Timonthy Lake.
2014	OthElecRev-Steam Sales	$879,684	In 2014, steam customers exceeded budgeted demand. ConAgra finished their plant expansion but had poor operational results from their own auxilary boiler, leading to higher than expected steam demands. In addition, Columbia River's and Collins' had a successful new product launch that led to increased steam demands.
2014	TransRevOthers-Non-Intertie	$1,032,814	ESS revenues exceeded projections because the direct access window was in November 2013 whereas the 2014 budget was developed in mid-2013.
2014	TransRevOthers-Intertie	$1,328,073	Intertie revenues exceeded budget due to: 1) the transfer of the Bank of America Leasing share of intertie to PGE in early 2014 (budget prepared in mid 2013), and 2) an increase in non-firm tansmission sales greater than expected.
2014	Offsetting variances	($30,370)	

PGE Other Revenue Forecast Variance Comments From Response to DR 412

Year	Revenue Source	Variance	Variance Explanation
2015	RentFrElecProperty-Joint Pole*	$824,991	For 2014 and 2015 forecasting, PGE based anticipated pole attachment rent on certain licensees receiving the reduced rental rate (RRR). This was based on their historical RRR status as well as projections that we had with regard to their status at the time of forecasting. Some of PGE's largest licensees did not end up qualifying for the reduced rate in both 2014 and 2015, resulting in them paying between $1.50 to $1.75 more per attachment than initially forecast. PGE is not privy to licensee forecasts for wireless activity and typically cannot anticipate activity increases until they start occurring. Due to technological improvements, wireless activity has significantly increased over the last few years, especially during 2014-2015. In addition to new wireless sites in the years in question (and the resulting make-ready revenue), modifications to existing sites resulted in higher annual rental amounts collected, and higher rental escalation than anticipated.
2015	Other Electric Revenues	$422,462	Park Revenues ($226k) - Recreation area visitation and subsequent revenue is very dependent on weather. The summers of 2014 and 2015 set attendance records for several recreation areas around the state, due to record setting temperatures that drew visitors to water based parks and campgrounds. Ultimately, revenues can be higher or lower than budgeted based on: 1) Variations in summer weather, and 2) winter snows and potential slow melt may affect the opening of PGE's higher elevation sites near Timonthy Lake. P-Card Rebate ($175k) - In 2015, PGE signed a five-year contract with Bank of America (BoA) for use of employee credit cards (Procurement Cards or P-Card). In signing this five-year contract PGE recieved a $175k signing bonus. This was not captured in the budget as the agreement of the signing bonus was determined through negotiations with BoA after PGE's budgets for 2015 had already been finalized.
2015	OthElecRev-Steam Sales	$721,713	In 2015, the price per thousand pounds ($/Klbs) of steam was higher than projected. In addition, the customer Columbia River's and Collin's new product launch successes from 2014 continued and their demand for steam remained stronger than expected.
2015	TransRevOthers-Non-Intertie	$1,610,598	ESS revenues exceeded projections because the direct access window was in November 2014 whereas the 2015 budget was developed in mid-2014.
2015	Offsetting variances	($137,667)	

PGE Other Revenue Forecast Variance Comments From Response to DR 412

Year	Revenue Source	Variance	Variance Explanation
2016	RentFrElecProperty-Joint Pole	$1,752,640	PGE received $1.3 million in revenue from a short-term project that entailed the following aspects: • PGE filed its 2016 general rate case in February 2015. • The external party gave notice of the project in the summer of 2015. • PGE and the external party agreed to proceed with the project in January 2016. At that time, PGE expected costs and revenues to equal and offset each other. • During 2016, the external party did not achieve the volume of projected activity but was obligated to pay the full amount of revenue based on the terms of the contract. • The external party cancelled the contract near the end of 2016. PGE also received approximately $0.4 million in 2016 for a joint inspection recovery pilot. This revenue offset the increase in both quantity and scope of inspections performed as part of the pilot. Because this was a pilot program, PGE did not have a basis for including an amount in the 2016 budget. Finally, PGE had a $0.1 million increase in revenue from permit processing, interim rent, sanctions, and violations charged to licensees for joint use activity, as well as additional wireless applications and site make-ready activity
2016	Offsetting variances	($170,719)	

CASE: UE 319
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 706

Exhibits in Support
Of Opening Testimony

June 16, 2017

Portland General Electric									
Carty Major Maintenance Accrual Deferral Balance Rollforwad									
								Staff	PGE
				Beginning	YTD		Deferred	Ending	Ending
Account	PS AWO	Description	Year	Balance	Expense	Collections	Expense	Balance	Balance
1823001	1000004762	CARTY MAJOR MAINT ACCRUAL	2015	0.00	0	0	0	0	0
1823001	1000004762	CARTY MAJOR MAINT ACCRUAL	2016	0.00	2,322,148	(2,250,925)	71,223	0	71,223
						Total	71,223		

Portland General Electric									
Coyote Springs Major Maintenance Accrual Deferral Balance Rollforwad									
								Staff	PGE
				Beginning	YTD		Deferred	Ending	Ending
Account	PS AWO	Description	Year	Balance	Expense	Collections	Expense	Balance	Balance
2284001	7000000322	COYOTE SPRINGS MAJOR MAINT ACCRUAL	1995	-	0	(222,008)	0	(222,008)	(222,008)
2284001	7000000322	COYOTE SPRINGS MAJOR MAINT ACCRUAL	1996	(222,008.00)	0	(2,664,096)	0	(2,886,104)	(2,886,104)
2284001	7000000322	COYOTE SPRINGS MAJOR MAINT ACCRUAL	1997	(2,886,104.00)	178,337	(2,664,096)	0	(5,371,863)	(5,371,863)
2284001	7000000322	COYOTE SPRINGS MAJOR MAINT ACCRUAL	1998	(5,371,863.00)	2,954,486	(2,664,096)	0	(5,081,473)	(5,081,473)
2284001	7000000322	COYOTE SPRINGS MAJOR MAINT ACCRUAL	1999	(5,081,473.06)	12,163,888	(2,664,096)	4,418,319	0	4,418,319
2284001	7000000322	COYOTE SPRINGS MAJOR MAINT ACCRUAL	2000	-	427,935	(2,664,096)	0	(2,236,161)	2,182,158
1823001	7000000322	COYOTE SPRINGS MAJOR MAINT ACCRUAL	2001	(2,236,160.98)	6,999,000	(3,025,071)	1,737,768	0	6,156,087
1823001	7000000322	COYOTE SPRINGS MAJOR MAINT ACCRUAL	2002	-	1,825,972	(4,107,997)	0	(2,282,025)	3,874,062
1823001	7000000322	COYOTE SPRINGS MAJOR MAINT ACCRUAL	2003	(2,282,025.00)	2,917,572	(4,108,006)	0	(3,472,459)	2,683,628
2540003	7000000322	COYOTE SPRINGS MAJOR MAINT ACCRUAL	2004	(3,472,459.00)	159,141	(4,108,000)	0	(7,421,318)	(1,265,231)
2540003	7000000322	COYOTE SPRINGS MAJOR MAINT ACCRUAL	2005	(7,421,318.00)	2,307,895	(4,108,000)	0	(9,221,423)	(3,065,336)
2540003	7000000322	COYOTE SPRINGS MAJOR MAINT ACCRUAL	2006	(9,221,423.00)	1,476,104	(4,108,001)	0	(11,853,320)	(5,697,233)
2540003	7000000322	COYOTE SPRINGS MAJOR MAINT ACCRUAL	2007	(11,853,319.62)	951,698	(2,133,034)	0	(13,034,656)	(6,878,569)
2540003	7000000322	COYOTE SPRINGS MAJOR MAINT ACCRUAL	2008	(13,034,656.46)	690,029	(2,044,272)	0	(14,388,899)	(8,232,812)
2540003	7000000322	COYOTE SPRINGS MAJOR MAINT ACCRUAL	2009	(14,388,899.17)	4,467,687	(2,044,272)	0	(11,965,484)	(5,809,397)
2540003	7000000322	COYOTE SPRINGS MAJOR MAINT ACCRUAL	2010	(11,965,483.91)	2,683,748	(2,044,272)	0	(11,326,007)	(5,169,920)
2540003	7000000322	COYOTE SPRINGS MAJOR MAINT ACCRUAL	2011	(11,326,007.44)	3,737,959	(2,044,272)	0	(9,632,320)	(3,476,233)
2540003	7000000322	COYOTE SPRINGS MAJOR MAINT ACCRUAL	2012	(9,632,320.04)	3,432,955	(2,044,272)	0	(8,243,637)	(2,087,550)
2540003	7000000322	COYOTE SPRINGS MAJOR MAINT ACCRUAL	2013	(8,243,636.56)	1,716,708	(2,044,272)	0	(8,571,201)	(2,415,114)
2540003	7000000322	COYOTE SPRINGS MAJOR MAINT ACCRUAL	2014	(8,571,200.52)	3,178,950	(4,411,753)	0	(9,804,003)	(3,647,916)
2540003	7000000322	COYOTE SPRINGS MAJOR MAINT ACCRUAL	2015	(9,804,003.21)	4,318,059	(4,411,753)	0	(9,897,697)	(3,741,610)
2540003	7000000322	COYOTE SPRINGS MAJOR MAINT ACCRUAL	2016	(9,897,696.57)	3,908,516	(3,745,872)	0	(9,735,053)	(3,578,966)
						Total	6,156,087		

Portland General Electric									
Port Westward I Major Maintenance Accrual Deferral Balance Rollforwad									
								Staff	PGE
				Beginning	YTD		Deferred	Ending	Ending
Account	PS AWO	Description	Year	Balance	Expense	Collections	Expense	Balance	Balance
1823001	3000000728	PORT WESTWARD MAJOR MAINT ACCRUAL	2014	0.00	7,285,931	(4,946,816)	2,339,115	0	2,339,115
1823001	3000000728	PORT WESTWARD MAJOR MAINT ACCRUAL	2015	0.00	5,576,404	(5,120,520)	455,884	0	2,794,999
1823001	3000000728	PORT WESTWARD MAJOR MAINT ACCRUAL	2016	0.00	4,564,139	(5,120,520)	0	(556,381)	2,238,618
						Total	2,794,999		

Portland General Electric									
Port Westward II Major Maintenance Accrual Deferral Balance Rollforwad									
					YTD		Deferred	Staff Ending Balance	PGE Ending Balance
Account	PS AWO	Description	Year	Beginning Balance	Expense	Collections	Expense		
2540003	3000000747	PORT WESTWARD 2 MAJOR MAINT ACCRUAL	2015	-	737,901	(967,608)	0	(229,707)	(229,707)
2540003	3000000747	PORT WESTWARD 2 MAJOR MAINT ACCRUAL	2016	(229,707.22)	287,209	(967,602)	0	(910,100)	(910,100)
							0		

MMA Exclusive of Deferred Expenses

Combined Gas MMA

	Beginning Balance	LTSA Expense	Amortization	Ending Balance	Average Balance
2016	$ (1,176,318)	$ 10,719,761	$ (12,084,919)	$ (11,201,533)	$ -
2017	$ (11,201,533)	$ 13,696,953	$ (15,236,213)	$ (12,740,793)	$ (11,971,163)
2018	$ (12,740,793)	$ 14,936,789	$ (13,924,362)	$ (11,728,366)	$ (12,234,579)
2019	$ (11,728,366)	$ 14,651,313	$ (13,924,362)	$ (11,001,414)	$ (11,364,890)
2020	$ (11,001,414)	$ 16,574,567	$ (13,924,362)	$ (8,351,209)	$ (9,676,312)
2021	$ (8,351,209)	$ 16,905,276	$ (13,924,362)	$ (5,370,295)	$ (6,860,752)
2022	$ (5,370,295)	$ 12,656,141	$ (13,924,362)	$ (6,638,516)	$ (6,004,406)

Carty MMA

	Beginning Balance	LTSA Expense	Amortization	Ending Balance	Average Balance
2016	$ -	$ 2,223,451	$ (2,250,925)	$ -	
2017	$ -	$ 4,707,872	$ (5,402,219)	$ (694,347)	$ (347,173)
2018	$ (694,347)	$ 4,993,994	$ (4,981,326)	$ (681,679)	$ (688,013)
2019	$ (681,679)	$ 4,527,157	$ (4,981,326)	$ (1,135,848)	$ (908,764)
2020	$ (1,135,848)	$ 6,014,714	$ (4,981,326)	$ (102,460)	$ (619,154)
2021	$ (102,460)	$ 5,578,300	$ (4,981,326)	$ 494,514	$ 196,027
2022	$ 494,514	$ 4,451,786	$ (4,981,326)	$ (35,026)	$ 229,744

Coyote MMA

	Beginning Balance	LTSA Expense	Amortization	Ending Balance	Average Balance
2016	$ (3,741,610)	$ 3,877,388	$ (3,745,872)	$ (9,735,053)	
2017	$ (9,735,053)	$ 4,016,663	$ (3,745,872)	$ (9,464,262)	$ (9,599,657)
2018	$ (9,464,262)	$ 4,538,837	$ (3,263,672)	$ (8,189,097)	$ (8,826,680)
2019	$ (8,189,097)	$ 4,518,664	$ (3,263,672)	$ (6,934,104)	$ (7,561,601)
2020	$ (6,934,104)	$ 4,665,795	$ (3,263,672)	$ (5,531,981)	$ (6,233,043)
2021	$ (5,531,981)	$ 4,827,109	$ (3,263,672)	$ (3,968,544)	$ (4,750,262)
2022	$ (3,968,544)	$ 1,574,492	$ (3,263,672)	$ (5,657,724)	$ (4,813,134)

PW1 MMA

	Beginning Balance	LTSA Expense	Amortization	Ending Balance	Average Balance
2016	$ 2,794,999	$ 4,236,352	$ (5,120,520)	$ (556,381)	
2017	$ (556,381)	$ 4,490,251	$ (5,120,520)	$ (1,186,649)	$ (871,515)
2018	$ (1,186,649)	$ 4,819,135	$ (5,120,520)	$ (1,488,034)	$ (1,337,342)
2019	$ (1,488,034)	$ 4,783,525	$ (5,120,520)	$ (1,825,029)	$ (1,656,532)
2020	$ (1,825,029)	$ 5,059,253	$ (5,120,520)	$ (1,886,296)	$ (1,855,663)
2021	$ (1,886,296)	$ 5,570,162	$ (5,120,520)	$ (1,436,654)	$ (1,661,475)
2022	$ (1,436,654)	$ 5,681,565	$ (5,120,520)	$ (875,608)	$ (1,156,131)

PW2 MMA

	Beginning Balance	LTSA Expense	Amortization	Ending Balance	Average Balance
2016	$ (229,707)	$ 382,571	$ (967,602)	$ (910,100)	
2017	$ (910,100)	$ 482,167	$ (967,602)	$ (1,395,535)	$ (1,152,817)
2018	$ (1,395,535)	$ 584,824	$ (558,844)	$ (1,369,555)	$ (1,382,545)
2019	$ (1,369,555)	$ 821,967	$ (558,844)	$ (1,106,432)	$ (1,237,994)
2020	$ (1,106,432)	$ 834,804	$ (558,844)	$ (830,472)	$ (968,452)
2021	$ (830,472)	$ 929,704	$ (558,844)	$ (459,612)	$ (645,042)
2022	$ (459,612)	$ 948,298	$ (558,844)	$ (70,158)	$ (264,885)

Colstrip MMA

	Beginning Balance	Overhaul Expense	Amortization	Ending Balance	Average Balance
2018	$ -	$ -	$ (2,336,172)	$ (2,336,172)	$ (2,336,172)
2019	$ (2,336,172)	$ 3,712,422	$ (2,336,172)	$ (959,921)	$ (1,648,046)
2020	$ (959,921)	$ 4,028,784	$ (2,336,172)	$ 732,691	$ (113,615)
2021	$ 732,691	$ -	$ (2,336,172)	$ (1,603,481)	$ (435,395)
2022	$ (1,603,481)	$ 3,939,652	$ (2,336,172)	$ -	$ (801,740)

MMA Inclusive of Deferred Expenses

Combined Gas MMA

	Beginning Balance	LTSA Expense	Amortization	Ending Balance	Average Balance
2016	$ (1,176,318)	$ 10,719,761	$ (12,084,919)	$ (3,541,537)	$ -
2017	$ (3,541,537)	$ 13,696,953	$ (15,236,213)	$ (5,080,797)	$ (4,311,167)
2018	$ (5,080,797)	$ 14,936,789	$ (13,924,362)	$ (4,068,369)	$ (4,574,583)
2019	$ (4,068,369)	$ 14,651,313	$ (13,924,362)	$ (3,341,418)	$ (3,704,894)
2020	$ (3,341,418)	$ 16,574,567	$ (13,924,362)	$ (691,213)	$ (2,016,316)
2021	$ (691,213)	$ 16,905,276	$ (13,924,362)	$ 2,289,701	$ 799,244
2022	$ 2,289,701	$ 12,656,141	$ (13,924,362)	$ 1,021,480	$ 1,655,591

Carty MMA

	Beginning Balance	LTSA Expense	Amortization	Ending Balance	Average Balance
2016	$ -	$ 2,223,450.65	$ (2,250,924.55)	$ 35,026.00	
2017	$ 35,026.00	$ 4,707,871.95	$ (5,402,218.91)	$ (659,320.97)	$ (312,147.48)
2018	$ (659,320.97)	$ 4,993,994.00	$ (4,981,325.95)	$ (646,652.91)	$ (652,986.94)
2019	$ (646,652.91)	$ 4,527,156.58	$ (4,981,325.95)	$ (1,100,822.28)	$ (873,737.60)
2020	$ (1,100,822.28)	$ 6,014,714.28	$ (4,981,325.95)	$ (67,433.95)	$ (584,128.12)
2021	$ (67,433.95)	$ 5,578,300.30	$ (4,981,325.95)	$ 529,540.41	$ 231,053.23
2022	$ 529,540.41	$ 4,451,785.54	$ (4,981,325.95)	$ -	$ 264,770.20

Coyote MMA

	Beginning Balance	LTSA Expense	Amortization	Ending Balance	Average Balance
2016	$ (3,741,609.57)	$ 3,877,387.66	$ (3,745,872.00)	$ (4,077,329.00)	
2017	$ (4,077,329.00)	$ 4,016,662.64	$ (3,745,872.00)	$ (3,806,538.36)	$ (3,941,933.68)
2018	$ (3,806,538.36)	$ 4,538,836.92	$ (3,263,671.84)	$ (2,531,373.28)	$ (3,168,955.82)
2019	$ (2,531,373.28)	$ 4,518,664.47	$ (3,263,671.84)	$ (1,276,380.65)	$ (1,903,876.97)
2020	$ (1,276,380.65)	$ 4,665,795.38	$ (3,263,671.84)	$ 125,742.89	$ (575,318.88)
2021	$ 125,742.89	$ 4,827,109.10	$ (3,263,671.84)	$ 1,689,180.16	$ 907,461.52
2022	$ 1,689,180.16	$ 1,574,491.68	$ (3,263,671.84)	$ (0.00)	$ 844,590.08

PW1 MMA

	Beginning Balance	LTSA Expense	Amortization	Ending Balance	Average Balance
2016	$ 2,794,998.91	$ 4,236,351.87	$ (5,120,520.00)	$ 1,340,708.00	
2017	$ 1,340,708.00	$ 4,490,251.45	$ (5,120,520.00)	$ 710,439.45	$ 1,025,573.72
2018	$ 710,439.45	$ 4,819,134.66	$ (5,120,520.00)	$ 409,054.11	$ 559,746.78
2019	$ 409,054.11	$ 4,783,525.05	$ (5,120,520.00)	$ 72,059.15	$ 240,556.63
2020	$ 72,059.15	$ 5,059,253.38	$ (5,120,520.00)	$ 10,792.53	$ 41,425.84
2021	$ 10,792.53	$ 5,570,162.22	$ (5,120,520.00)	$ 460,434.75	$ 235,613.64
2022	$ 460,434.75	$ 5,681,565.47	$ (5,120,520.00)	$ 1,021,480.22	$ 740,957.49

PW2 MMA

	Beginning Balance	LTSA Expense	Amortization	Ending Balance	Average Balance
2016	$ (229,707.22)	$ 382,570.65	$ (967,602.00)	$ (839,942.00)	
2017	$ (839,942.00)	$ 482,166.83	$ (967,602.00)	$ (1,325,377.17)	$ (1,082,659.59)
2018	$ (1,325,377.17)	$ 584,823.85	$ (558,844.03)	$ (1,299,397.35)	$ (1,312,387.26)
2019	$ (1,299,397.35)	$ 821,967.18	$ (558,844.03)	$ (1,036,274.19)	$ (1,167,835.77)
2020	$ (1,036,274.19)	$ 834,803.71	$ (558,844.03)	$ (760,314.51)	$ (898,294.35)
2021	$ (760,314.51)	$ 929,704.24	$ (558,844.03)	$ (389,454.30)	$ (574,884.40)
2022	$ (389,454.30)	$ 948,298.32	$ (558,844.03)	$ -	$ (194,727.15)

Colstrip MMA

	Beginning Balance	Overhaul Expense	Amortization	Ending Balance	Average Balance
2018	$ -	$ -	$ (2,336,171.75)	$ (2,336,171.75)	$ (2,336,171.75)
2019	$ (2,336,171.75)	$ 3,712,422.40	$ (2,336,171.75)	$ (959,921.10)	$ (1,648,046.43)
2020	$ (959,921.10)	$ 4,028,784.00	$ (2,336,171.75)	$ 732,691.15	$ (113,614.98)
2021	$ 732,691.15	$ -	$ (2,336,171.75)	$ (1,603,480.60)	$ (435,394.73)
2022	$ (1,603,480.60)	$ 3,939,652.35	$ (2,336,171.75)	$ -	$ (801,740.30)

Rate Base Adjustment	
PGE MMA Balance	($5,080,797)
Staff MMA Balance	($12,740,793)
Staff Ratebase Adjustment	**($7,659,996)**

Major Maintenance Accrual Adjustment	
PGE Proposed MMA Expense	$16,260,534
Replace Colstrip MMA with 3-year Average	$244,230
Remove Gas Plant MMA Expense	($13,924,362)
Return MMA Balance	($12,740,793)
Staff Total MMA Expense	($10,160,391)
Staff MMA Expense Adj.	**($26,420,925)**
NVPC Expense Adj.	$14,936,789
Combined Base Rate and NVPC Adj.	**($11,484,135)**

CASE: UE 319
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 800

Opening Testimony

June 16, 2017

Q. Please state your name, occupation, and business address.

A. My name is Scott Gibbens. I am a Senior Economist employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. I will discuss PGE's proposed expense levels for customer services and environmental and licensing services (ELS). In each case, I will present a background of the issue, Staff's analysis, and Staff's recommendation for the Commission.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared Exhibit Staff/801, which is PGE's Response to Staff DR No. 466 and Exhibit Staff/802, which includes my calculation of Staff's ELS adjustment.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1: CUSTOMER SERVICES

Q. What is the Company's proposal for Customer Services expense in its filing?

A. PGE proposes to increase non-labor Customer Services expense, excluding uncollectible accounts and the Customer Engagement Transformation (CET), from $14.6 million in base year 2016 to $16.7 million in the test year.[1] This represents an increase of $1.9 million or 13 percent. The Company states that the reason for the increase is due to investments in energy storage, electric vehicles, distributed generation, other emerging technologies, and demand response programs (new programs).[2]

Q. How has the Commission treated this issue in the past?

A. There were no adjustments made to Customer Services in PGE's last rate case (Docket No. UE 294). In Docket No. UE 283, the Commission approved a stipulated adjustment of ($277,000) to Customer Assistance expense recorded in FERC Account No. 908.[3]

Q. Please describe Staff's review and analysis of PGE's Customer Services expense.

A. Staff's review included analyzing trends, transactional details, and adjustments proposed by PGE. Staff looked at the annual increase in these expenses over the past five years to determine whether the proposed increase in the test year is consistent with historical increases. Because these costs are highly

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[1] PGE/900, Stathis - Dillin/4, Table 1, for discussion on Uncollectibles see Staff/400, for CET see Staff/1100.
[2] PGE/900, Stathis – Dillin/3-5.
[3] See Order No. 14-422, p.4

dependent on the number of customer accounts being served by PGE, Staff analyzed the number of dollars spent per customer on customer service programs. Table 1 below summarizes Staff's findings regarding the historical data.

Table 1

	2014 Actuals	2015 Actuals	2016 Actuals	2017 Budget	PGE 2018 Forecast
Customer Services Total	$15,284,548	$14,761,756	$14,801,858	$13,667,374	$16,708,691
Year/Year Difference		($522,792)	$40,102	($1,134,484)	$1,906,833*
Yr/Yr % increase		-3.4%	0.3%	-7.7%	12.9%*
$/Customer	$20.78	$19.88	$19.67	$17.93	$21.64

* From 2016 Actuals

In reviewing the transaction details, Staff aimed to identify which specific accounts and expenses were the cause for the increase. PGE has forecast an increase of $676,753 specifically for the new programs. This represents 35% of the requested increase. Removing that increase from the forecasted expense, PGE is then forecasting to spend $20.77 on each customer. This is similar to 2014 actuals but higher than either of the previous two years or the 2017 budget.

In reviewing the new programs PGE proposed, Staff has no issues with them. In Staff's opinion they are correctly aimed at providing a better service to customers and improving the offerings and satisfaction of rate payers. However, PGE states in its opening testimony that it has:

> Implemented projects that improve service, increase efficiency, and provide benefits and convenience to customers in how they interact with PGE such as

> paperless billing and automated web-enabled 'customer move' service requests.[4]

This means that PGE has invested in many programs which have a potential to provide cost savings to PGE. Due to this, the dollar per customer metric is a good benchmark to use in evaluating PGE's efficiency in providing customer service.

Q. What is Staff's proposed adjustment?

A. Staff followed the following steps. First, solely for the purpose of developing a multi-year trend, Staff removed the added expense for the new programs PGE cited as the reason for the increase. Then second, Staff took the three-year (2014-2016) average of dollars spent per customer in order to calculate a reasonable expectation of Customer Services expense for the test year. The total adjustment comes to $506,817.[5] Staff believes a three-year average perhaps overstates Customer Service expense because Table 1 shows a downward trend in cost-per-customer. The dollars-per-customer cost in 2014 is $20.78 and falls to $19.67 in 2016. Staff's adjustment provides PGE with this full amount of added expense for 2018, while incorporating Staff's three-year average value.

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[4] PGE/900, Stathis – Dillin/3-4 lines 21-1.
[5] $506,817 = $16,708,691 – ($20.11)(772,010) - $676,753.

ISSUE 2: ENVIRONMENTAL AND LICENSING SERVICES

Q. What is the Company's proposal for ELS expenses in this filing?

A. PGE proposes inclusion of $2.2 million in A&G costs for ELS. PGE states that 2016 actuals were $4.4 million. However as a result of the UM 1789 Commission decision, PGE removed all costs and revenues associated with the Portland Harbor Superfund Sites (Portland Harbor), the Natural Resource Damage obligation (NRD), the Downtown Reach portions of the Willamette River (Downtown Reach), and the Harborton Restoration Project (Harborton) (Together called "Remediation Projects") from base rates.[6]

Q. Please provide background to the Commission decision in UM 1789.

A. Commission Order No. 17-071 authorized the implementation of Schedule 149, an automatic adjustment clause (AAC) with the purpose of environmental remediation cost recovery for Portland Harbor and Downtown Reach sites. As a part of the stipulated agreement, the $3.56 million already included in base rates for the environmental remediation of those projects was included as a credit to the associated balancing account (PHERA) of Schedule 149. Under Order No. 17-071, the amount in base rates was to be removed along with the credit posting to the balancing account.

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[6] PGE/600, Lobdell - Tooman/27 line 3.

Q. If PGE removes all of the remediation projects costs consistent with Order No. 17-071, is there any corresponding action required with respect to recovery of those costs?

A. Yes. When the $3.56 million is removed from base rates, those monies would no longer be credited to the Portland Harbor Environmental Remediation Account (PHERA) account.

Q. How did Staff analyze this issue?

A. Staff reviewed the filing information and work papers looking at historical trends. Staff also compared PGE's UE 319 filing to information filed in UM 1789 and UE 294. Staff's main concern is that PGE is forecasting costs for ELS that were not included in base rates UE 294. In PGE's opening testimony, it states that compared to 2016 actuals, ELS costs charged to A&G still decrease by approx. $0.8 million when amounts transferred to the PHERA are not considered.[7] However, Staff believes that is somewhat misleading. Comparing PGE's forecasted costs between the two test years reflects that PGE is asking for an increase of $1.2 million. Table 2 below illustrates Staff's concern.

Table 2

	Total ELS (A)	Remediation Projects (B)	Other ELS (C)	PGE Requested ELS (D)	Difference (D) – (C)
UE 294 Base	$4,551,763	$3,563,460	$991,763	$2,226,183	$1,234,420
2016 Actuals	$4,357,082	$1,311,696	$3,045,386	$2,226,183	-$819,203

[7] PGE/600, Lobdell – Tooman/27, line 11.

In comparing the test year to 2016 actuals, ELS base amounts do decrease by the amount referenced by PGE, however when comparing to PGE's previous rate case, it is evident that the base ELS amount is increasing. After further review, Staff found that the $3.56 million referenced in Commission Order No. 17-071, was based on an A&G account that included labor. PGE stated in response to Staff DR No. 466 that the amount included in the PHERA would not include labor costs.[8] This potentially reduces the total amount removed from base rates to $3.1 million. However, PGE is representing in this filing that only $2.54 million is included in base rates for Remediation Projects. Staff believes that in this circumstance, PGE is not complying with Commission Order No. 17-071 or a stipulation, which it signed on to, that states:

> Parties agree that $3.56 million per year was included in base rates for environmental remediation-related activities in the Portland Harbor and Downtown Reach in PGE's last general rate case.

Q. What is Staff's recommendation for this issue?

A. Staff believes that PGE should comply with the agreement from UM 1789 and remove the sum it stated was in base rates for the Remediation Projects. Staff's adjustment totals approximately $1.1million.[9] To calculate this, Staff began with the A&G amount included in base rates for all ELS in UE 294. Then Staff removed the amount which PGE stated was in base rates in UM 1789. Staff then calculated the increases requested by PGE

[8] Staff/801, PGE's response to Staff DR No. 466.
[9] See Staff/802.

between UE 294 and UE 319 in all accounts other than the account which collects costs related to the Remediation Projects. This resulted in Staff's proposed adjustment of $1.1 million.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 319
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 801

Exhibits in Support
Of Opening Testimony

June 16, 2017

April 20, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 466
Dated April 10, 2017

Request:

Regarding UE 319/PGE/600, Lobdell – Tooman/27: Please provide the non-labor A&G, and Production O&M Costs associated with Environmental and Licensing Services not including Portland Harbor, NRD, or Harborton costs. Please include 2014-2016 actuals, UE 294 approved rates, 2017 budget, and 2018 test year. Please include a narrative explanation of differences between years of greater than 10% change and a description of the costs covered by ELS accounts now that PGE's major environmental remediation projects are no longer included.

Response:

Attachment 466-A provides the 2014-2016 actuals, Docket No. UE 294 approved expenses, 2017 budget, and 2018 forecasted non-labor Production Operation and Maintenance (O&M) and Administrative and General (A&G) Environmental and Licensing Services (ELS) expenses and the variance between these years. No issues were raised regarding PGE's 2016 estimation for ELS expenses in the 2016 general rate case process.

Production O&M:

- The $0.6 million variance between 2014 and 2015 actuals was due to increased expenses in 2015 for PGE's Tucannon River Wind Farm, Pelton-Round Butte, and West Side Hydro facilities:
    - Tucannon River Wind Farm came on-line in 2015. O&M support work provided by ELS included initial permit implementation and activities such as: 1) establishing programs and conducting surveys as required, 2) developing a site manager's environmental compliance guide, 3) evaluation of waste streams and disposal methods, and 4) familiarization with Washington state regulations;
    - There were also increased costs associated with Oregon Department of Fish Wildlife (ODFW) co-op agreements and Round Butte Hatchery operations for the salmon and steelhead reintroduction program; and

  - In 2015, the West Side fisheries team was required to conduct a one-time Passage Survival Evaluation study.

- The approximate $0.8 million variance between 2015 and 2016 actuals was primarily due to increased compliance activities specified in the FERC licenses for PGE's West Side Hydro and Pelton-Round Butte hydro projects:
  - The West Side Hydro increase in O&M expenses is due to the FERC license requirement that PGE commence placement of gravel along the Clackamas River below the River Mill facility in 2016. The purpose of this activity is to mitigate the impact of PGE's three main-stem dams which block the migration of alluvial material. For additional information please see Docket No. UE 294, PGE Exhibit 700, Section IV;
  - The 2016 O&M expenses increase related to Pelton-Round Butte is due to the FERC license test and verification study requiring the implementation of an Acoustic Doppler Current Profile (ADCP) study in Lake Billy Chinook and additional hatchery expenses for the production of Chinook salmon and steelhead smolts for release upstream as part of the fish reintroduction program. For additional details please see Docket No. UE 294, PGE Exhibit 700, Section IV.

A&G:

- The approximate $1.0 million variance between both 2015 actuals and UE 294 approved expenses versus 2016 actuals was due to Beaver Tank Farm Remediation expenses in 2016. The first phase of the project began in late 2014 and carried into 2015 and included soil and groundwater investigations in the tank farm. In 2016, PGE conducted extensive excavation and offsite disposal of soil contaminated with diesel fuel and removal of unused pipes within the Beaver Tank Farm. This work remediated recent and historical contamination areas. In 2016, PGE also conducted a decommissioning study for the entire Beaver facility including the tank farm.

PGE does not have specific accounts to cover ELS expenses. Instead, PGE has specialized departments for Environmental and Licensing Services activities.

The environmental expenses currently covered by PGE's Environmental and Licensing Services departments are:

- **Department 172: Parks and Recreation Services Expenses**
  As part of PGE's obligations under the Pelton Round Butte and Clackamas licenses, the company is required to establish and maintain recreation facilities and sites along the rivers affected by the dams. A&G work includes: maintenance of hiking trails, shelters and facilities, sites, plumbing, and electricity; removal of unsafe trees; janitorial support and refuse removal; temporary labor to host the parks; road maintenance fees to the United States Forest Service (USFS); law enforcement fees (Jefferson County); replacing signage as needed; brochure printing; etc.

- **Department 841 (Cleanup and Terrestrial Services): Contamination Cleanup Expenses**
  While the non-labor expenses associated with Portland Harbor are captured in the Portland Harbor Environmental Remediation Account (PHERA) and are no longer in

base customer prices, the labor associated with that project is. Cleanup activities that are not associated with Portland Harbor include: response to all oil and hazardous waste spills; confirmation sampling after cleanup activities; work on legacy sites with contaminant issues, and management of emergent environmental obligations; etc.

Terrestrial support is provided as needed for all generating facilities, including license obligations for PGE's hydroelectric dams. This support includes: monitoring species in license and permit areas and as identified by licenses and permits; weed control; studies and projects per license/permit obligations; support during license deviations; etc.

- **Departments 842 (Eastside Biological Services) and 843 (Westside Biological Services): Hydro Licensing Expenses**
  PGE's hydroelectric projects require the implementation of a series of license obligations in partnership with tribal representatives, environmental organizations, and state and federal resource agencies. This work involves the development, implementation, and reporting of natural resources studies, resource monitoring programs, operational compliance reports, and engineering designs of new features added to the hydroelectric projects. Significant effort also goes into communication with the Federal Energy Regulatory Commission (FERC) and stakeholders on the status of the license implementation and negotiating the schedules of license milestones.

  Aquatic support includes: fish passage and survival; dissolved oxygen levels and river temperatures monitoring and maintenance; studies and projects per license obligation; support during license deviations; etc.

- **Department 844: Environmental Compliance and Licensing Expenses**
  Compliance support is company-wide, including generation, facilities, and transmission and distribution areas. This work varies by site and operations, but generically includes: environmental regulatory compliance monitoring; reporting to agencies; preparation of applications for and renewal/amendment of necessary permits; air quality testing and reporting; support with hazardous and universal waste determination and removal; support during agency inspections, responses to permit deviations, cultural resource regulatory compliance; environmental compliance reviews of facilities; sampling in support of construction work; drinking water quality studies; investigation and scoping for new projects; evaluations of properties prior to acquisition (Phase I & IIs); management of PGE's avian protection program; etc.

UE 319

Attachment 466-A

Provided in Electronic Format only

Environmental and Licensing Services Non-Labor Expense Variances
2014 - 2018

CASE: UE 319
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 802

Exhibits in Support
Of Opening Testimony

June 16, 2017

Exhibit 802

is Excel spreadsheets

(Provided in electronic format)

CASE: UE 319
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 900

Opening Testimony

June 16, 2017

Q. Please state your name, occupation, and business address.

A. My name is Kathy Zarate. I am a Utility Economist employed in the Energy Rates, Finance, and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My educational background and work experience is set forth in my Witness Qualification Statement, which is found in Exhibit Staff/901.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to specific issues in Portland General Electric Company's (PGE or Company) request for a general rate revision. I respond to the issues of gains on sales of utility property, operating plant materials and supplies non-fuel, and PGE's proposed expenditures for research and development.

Q. Did you prepare exhibits for this docket?

A. Yes. I have prepared the following exhibits:

Exhibit 901 — Witness Qualifications Statement.
Exhibit 902 — PGE Responses to Staff Data Request (DR) Nos. 165, 166, and 167 regarding gains on sales of utility property.
Exhibit 903 — PGE responses to Standard DR No.104 and to Staff DR Nos. 169, 170, and 170 explaining advertising and marketing.
Exhibit 904 — PGE responses to Standard DR Nos. 89 and 90 and Staff Dr Nos. 222 and 223 regarding Dues, Donations, and Memberships.
Exhibit 905 — PGE responses to Staff Data Request Nos. 224, 225, 226, and 227 relating to Research and Development.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1: GAINS AND LOSSES ON SALES OF UTILITY PROPERTY

Q. Please describe your review regarding gains and losses on utility property sales.

A. My review of PGE's treatment of gains and losses on utility property sales within this general rate case filing included several activities. First, I reviewed the Company's testimony and reviewed PGE's recent history of property sales filings. Second, I participated in a phone conference with PGE personnel. Third, I sent five data requests to verify the gains and losses on utility property sales.

Q. What is the historical treatment for PGE property sales by the Commission?

A. The Company maintains a property sales balancing account to flow through gains and losses to customers.

Q. Did you make any adjustments to PGE test-year expenditures to account for gains on property sales?

A. No. Since its last general rate case, PGE has recorded gains and losses in its property sales balancing account and will amortize them through its Schedule 105 for "Regulatory Adjustments." Therefore, I propose no adjustment on this issue.

ISSUE 2: Advertising

Q. Does the Commission have a standard policy regarding ratemaking treatment of advertising-related expenses?

A. Yes. OAR 860-026-0022 sets out how advertising-related expenses are addressed in a rate case.

Q. How did you perform your analysis of PGE's proposed advertising expenses?

A. Staff reviewed the Company's responses to a Standard Data Request No. 104 and other data requests explaining advertising and marketing, which are responses to Staff DR Nos. 169 and 170. In response to Staff DR No. 170, PGE provided a breakdown of its proposed 2018 advertising budget by category, and Staff reviewed the transaction-level detail of the Company's 2016 and 2017 spending on advertising and marketing activities.

Q. What does the Company include in its Test Year Revenue Requirement for advertising expense?

A. The following shows PGE's 2018 budget for advertising and its 2018 Test Year Forecast.

Table 1.

FERC Account	PGE Account	Account Description	Budget 2018	2018 Test Year(Forecast)	Category
909	9090001	Informational Advertising	$2,008,985	2,034,762	A
909	9090001	Legally Mandated Advertising	$25,777	($25,777)	B
930.1	9301001	Institutional/Promotional Advertising	$707,617	(707,617.33)	C*
417.1	4171003	Political/Non Utility Advertising	$0	$0	D**
417.1	4171005	Political/Non Utility Advertising	$12,360	($12,360)	D**
182.3		EE & Conversion Advertising	$0	$0	E
		2018 Advertising Budget	$2,754,739		
		2018 Test Year		$2,008,985	
*	Remove 100% of Account 9301001				
**	Not included in base rates				

Q. What is Staff's assessment of PGE's proposed 2018 Test Year advertising expense?

A. PGE appropriately complied with the Commission's rule, OAR 860-026-0022.

Q. Please explain how Staff came to this conclusion.

A. According to OAR 860-026-0022(2)(a), Category A advertising expenses are "[e]nergy efficiency or conservation advertising expenses that do not related to a Commission-approved program, utility service advertising expenses, and utility information advertising expenses." Category A advertising expenses are presumed reasonable if they are no more than 0.125 percent of the revenue requirement. This level of spending translates to roughly $2.25 million. PGE has included in its filing a Category A expense forecast of $2.1 million, which is presumed reasonable under the rule. In addition, the proposed budget for spending in this category is flat, relative to the Company's actual spending in 2016.

Category B expense is for legally mandated advertising and under

OAR 860-022-0022(2)(b) is presumed just and reasonable. Here again, PGE's proposed spending is consistent with actual spending in 2016.

Category C advertising expense is for institutional and promotional advertising. The Company must provide justification as to why it is just and reasonable to include in rates. The Company in its initial filing does not include expense for Category C advertising in its proposed revenue requirement.

Category D expenses are for political and nonutility advertising. They are presumed to be not just and reasonable for rate-making purposes. PGE does not include Category D advertising expense in its proposed revenue requirement.

Category E expenses are for advertising Commission-approved energy efficiency and conservation programs. These expenses may be capitalized. The Company proposes no spending on Category E advertising in the Test Year.

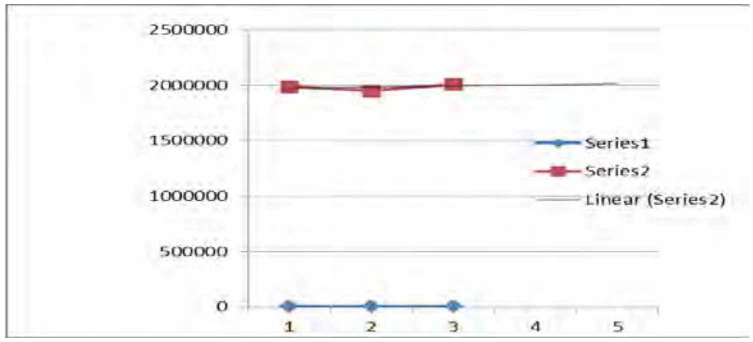
Q. How did Staff analyze advertising expense at the transaction-level?

A. Staff reviewed all transactions in FERC accounts relating to advertising and marketing for the 2016 base year. For all categories presumed reasonable expenses proposed spending in 2018 is flat, relative to actual spending in 2016 and forecasted 2017 expense, as shown in the following table and graph.

Table 2.

Years	1	2	3
	2016	2017	2018
TOTAL	1,988,883	1,949,093	2,008,985

Figure 1.



Q. Did you make any adjustments to PGE test-year expenditures to account for advertising expenses?

A. No, I conclude that PGE's advertising expenses included in its filing are consistent with Commission administrative rules and no adjustment is warranted.

ISSUE 3: DONATIONS, DUES AND MEMBERSHIPS

Q. What is the Commission's historical treatment for Donations, Dues and Memberships?

A. In accordance with our Oregon Administrative Rules, regulated energy utilities may not include in rates the costs associated with charitable contributions and donations. These are charged "below-the-line".

Also, 100% of prudently incurred costs of membership in industry research groups are allowed by the Commission, 100% of non-utility related memberships should be excluded and, 75% of national, regional trade memberships are allowed.

In addition, according to long-standing Staff practice, a utility must support memberships and dues in its rate case and if the utility does not identify the memberships underlying the cost, the expenses should be disallowed.[1]

Q. Please discuss your review of expenses relating to dues, donations, and memberships.

A. PGE's responses to Standard DR Nos. 89 and 90 and to Staff DR Nos. 222 and 223 contained information regarding dues, donations, and memberships. The Company provides a narrative explanation regarding charitable contributions and donations recorded in FERC Accounts 426 that are charges recorded below-the-line, and are not included in PGE's proposed revenue requirement for the 2018 test year. Based on the Company's responses, I

[1] *See* UG 305 - Staff/600, Zarate/4-5.

requested transaction-level detail for that FERC Account number.

PGE provided an MS excel spread sheet for FERC Accounts 921, 926, and 930 showing amounts for memberships. However, the level of projected spending was not totally evident. I therefore also requested transaction-level detail for these accounts and asked the reason why those accounts have been increasing since 2016.

Memberships

Table 3.

Account	**Topic**	**2016**	**2017**	**2018**	Adjustment
557	Memberships	2,500	130	130	None
580	Memberships	1,204	11,904	12,188	None
926	Memberships	1,205	3,500	3,584	100% (3,584)
921	Memberships	58,518	125,214	128,207	25% (32,051.75)
930	Memberships	3,025,446	3,130,927	3,428,311	25% (857,077.75)
Total		$3,088,873	$3,271,675	$3,572,420	$(892,713.5)

Q. Did you make any adjustments to PGE's dues, donations, and memberships test-year expense?

A. Yes, I identified numerous instances where PGE did not clearly identify the organization associated with the expense or explain how such membership provides customer benefits. I recommend that the Commission disallow costs for unexplained memberships recorded in FERC Accounts 921, 926, and 930, which is 100% from FERC Account 926 and 25% from Accounts 921 and 930 each, detailed above.[2] My adjustment for dues, donations and memberships is ($892,713).

[2] *See* Table 3.

ISSUE 4: RESEARCH AND DEVELOPMENT

Q. What is the amount of the research and development (R&D) budget PGE proposed to be included in revenue requirement for the 2018 test period?

A. PGE includes roughly $3.1 million.

Q. How does that amount compare with actual R&D spending for the year 2016?

A. PGE is requesting a substantial increase in expenditures relating to R&D as compared to the 2016 level. As noted in PGE/600, Lobdell-Tooman/14, PGE is requesting about $1.0 million more in this case, which represents a 50 percent increase.

Q. What do you find are the major reasons for the increase?

A. There are two main reasons. First, PGE is proposing a roughly $0.8 million increase in R&D expenditures. Second, PGE is proposing a separate administrative cost of $0.2 million, a cost not requested previously.

Q. Do you support the proposed increase in R&D?

A. No. While Staff supports R&D, we have to take into consideration cost as well. In looking over the proposed R&D projects, it appears to Staff that some projects could be eliminated from the test year due to considerations such as:

- Possibility of learning from similar research efforts conducted elsewhere;
- Postponement; or
- Limited value.

Staff believes the costs for projects that could be eliminated or postponed total $0.665 million. While Staff has some projects in mind that fall in this category, Staff believes it would be useful to meet with other parties to see if agreement could be reached on which projects to exclude from the test year forecast.

Q. Do you have some examples of R&D that Staff believes could be removed from PGE's list?

A. Yes. Without the benefit of discussion with the other interested parties, some of the R&D projects that could be removed from the list are:

- Project ID #10 relating to Nuscale Modular reactor
- Project ID # 42 relating to exploring non-intrusive customer load monitoring
- Project ID # 43 relating to load shifting at small scale using HVAC
- Project ID # 44 relating to Practicality of 100% Solar Roofing
- Project ID #18 relating to Torrefied Fuel Tests

Most of the projects noted above were ranked lower in priority by PGE in response to Staff Data Request No. 226. The last project relating to torrefaction should be captured through another mechanism, assuming it is supported, rather than building into base rates. This project is costly and is time-limited so it seems not appropriate to treat as an ongoing expense in base rates.

Second, with regard to administrative costs for R&D, Staff does not support PGE's proposal to include $0.2 million in revenue requirement. PGE has been managing R&D for several years without identifying specific administrative costs. PGE does not explain how the $0.2 million would be spent or why it is needed, other than to note that it used to have 1.7 FTEs dedicated to R&D and now has one. Therefore I propose an adjustment of $0.885 million, representing an R&D budget of $2.215 million.

Q. Do you have a table to show the details of your adjustments?

A. Yes, I do.

Table 4.

	Dollars
	(000,000)
PGE Proposed R&D Expenditures	$3.100
Project #10 NuScale Moldular Reactor	$0.005
Project #42 Non-instrusive load monitoring	$0.040
Project #43 Load shifting using HVAC	$0.060
Project #44 Practicality of 100% Solar Roofing	$0.040
Project #18 Torrified fuel Tests	$0.300
Project #51 Collaboration with BPA	$0.100
Project #12 Battery Back-up demonstration	$0.100
Project #53 Exploring Digital Assistant	$0.040
Administrative cost inclusion	$0.200
Total Staff deductions	**$0.885**
Net	$2.215

Q. Does that still represent a sizable increase in R&D expenditures?

A. Yes. Going from a 2016 level of $2.1 million to $2.2 million represents a 5 percent increase, which is more in line with PGE's general rate increase filing in this docket.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 319
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 901

Witness Qualifications Statement

June 16, 2017

WITNESS QUALIFICATION STATEMENT

NAME:	Kathy Zarate
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Analyst Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE., Suite 100 Salem, OR. 97301
EDUCATION:	Bachelor of Arts, Economics Oregon State University, Corvallis, Oregon Bachelor Degree in Law Republic University, Santiago, Chile
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon since April 2016, with my current position being a Utility Analyst, in the Energy - Rates, Finance and Audit Division. My responsibilities include research, analysis, and recommendations on a range of regulatory issues such as review of affiliated interest filings, property sales applications and rate proposals. I have approximately 10 years of professional experience in contracting and audit review work, including: • Six years as contract specialist for 3 Com, Santiago, Chile, with responsibilities including coordinating and preparing contracts with resellers, reviewing company books and records, coordinating logistics in business delivery, and investigating property theft.

CASE: UE 319
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 902

Exhibits in Support
Of Opening Testimony

June 16, 2017

March 17, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 165
Dated March 8, 2017

Request:

Has the Company sold any utility property since the effective date for rates in the last rate case? If so, please describe the transaction and provide any gain from the property sale and the account in which it was recorded.

Response:

Yes. PGE has sold property since its last general rate case, UE 294. See Attachment 165-A for a copy of PGE's 2015 Annual Property Sale report (RE-65) filed April 2016.

See also PGE notices, docketed as UPN-22 filed on November 14, 2016, and UPN 33 filed on March 7, 2017. The UPN notices list transactions between $25,000 and $100,000 for the years 2014, 2015, 2016, and January of 2017.

PGE had three land sales that will be reported in the 2016 Annual Property Sale report (RE-65) as listed in the below table. The net proceeds on these sales were recorded to Account 254 – Other regulatory liabilities, PGE's property sales balancing account.

Docket No.	Property Description	OPUC Order No.	Net Proceeds
UP 331	Sale to Newberg property to Oregon Department of Transportation (ODOT)	15-402	$99,289
UP-340	Sale of St. Mary's Substation (Beaverton) to Washington County	16-183	$153,104
Not Applicable	Sale of Right of Way (Washington County)	Not Required	10,900

UE 319

Attachment 165-A

Provided in Electronic Format only

PGE 2015
Property Sale Report RE-65

March 17, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 166
Dated March 8, 2017

Request:

Please provide a listing of all property sales, including the sales price, net book, net gain, date of sale, and brief description of property sold from calendar 2012 to present for any plant not located in Oregon but included in Oregon rates as a result of PGE allocations procedures.

Response:

See Attachment 166-A for a listing of property transactions related to the Colstrip Generating Plant, PGE's only out of state operating plant.

PGE is a 20% owner of Units 3 and 4 and receives a small portion of these sale proceeds based on its ownership percentage. Talen Energy operates the Colstrip Plant and supplies PGE with sales information.

From the Colstrip project, PGE is providing responses to the sale of certain assets that are described as town site properties. The town site properties (individual home sites) were purchased as housing for the construction workers during Plant construction and as living facilities for employees involved in Plant operations. When Colstrip Units 3 & 4 became operational in 1984, these costs were included as part of the original Colstrip plant cost, and recorded to FERC account 311 – Steam Plant- Structures and Improvements. At various times since the Plant began operations there have been sales of these properties as the operator of the project determines that a town site is no longer needed utility purposes. There are limited opportunities to make any sales at this location and it takes time for any sale to occur. The value of these assets was recorded as part of the overall capital cost recorded to FERC Account 311 Steam Plant Structures and Improvements. No specific details exist on each property. PGE receives a share of the proceeds which are distributed to all co-owners based on their percentage share of ownership in Colstrip.

All proceeds are recorded as salvage to FERC Account 108 – Accumulated provision for depreciation. The retirement of Original Book cost is recorded to FERC Account 108 and these costs become part of the overall depreciation calculations currently in place as approved under OPUC Order No. 14-297.

UE 319

Attachment 166-A

Provided in Electronic Format only

Property Sale List
Colstrip Property

March 17, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 167
Dated March 8, 2017

Request:

For any net gains identified in the Company's response to the two data request above, please note whether and to what extent each of such gains from the respective transactions were used to reduce plant in service or otherwise provided to the benefit of Oregon customers. If not, for each such transaction, explain why such gains were not flowed through to the benefit of Oregon customers.

Response:

All net gains flow back to Oregon customers through depreciation or through the property deferral mechanism. The sales discussed in PGE's Response to OPUC DR 166 are recorded to FERC Account 311 Steam Plant – Structures and Improvements and are treated as depreciable Production Plant assets and recorded to salvage in the appropriate Depreciation group, not property sales.

PGE records all property sale gains to the following accounts:

- FERC 108 Accumulated provision for depreciation of electric utility plant, (a component of depreciation expense and reduces the expense over time); or

- FERC 254, Other Regulatory liabilities and returned to customers through the property deferral mechanism.

CASE: UE 319
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 903

Exhibits in Support
Of Opening Testimony

June 16, 2017

February 28, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Standard Data Request No. 104
Dated February 28, 2017

Request:

For the questions below related to advertising expense, please see the definitions and descriptions in OAR 860-026-0022. For questions related to promotional activities or concessions, please see OAR 860-026-0015 & 0020.

a. Please identify the Category A advertising expense included in the Test Year; including references to the appropriate testimony and / or exhibit pages.

b. Please provide a work paper that shows the calculation of the Category A limit provided in OAR 860-026-0022 (3) (a).

c. If the Test Year Category A advertising expense exceeds the OAR 860 026-0022 (3) (a) limit, please provide support for including the additional expense in rates.

d. Please identify the Category B advertising expense included in the Test Year; including references to the appropriate testimony and / or exhibit pages.

e. For any Category C advertising expense included in the Test Year revenue requirement that is associated with a promotional activity or a promotional concession program, please provide a summary table that includes:

i. A description of the activity or program, and justification for inclusion into rates;
ii. A breakout of the related expense by labor & non-labor; and
iii. The FERC and internal utility account to which the expense will be booked and include references to appropriate exhibit pages.

f. Please identify any other budgeted advertising expense for the test year that will NOT be included in base rates, including below-the-line or nonutility expense, or advertising expense expected to be collected through a tariff. Please include how the expense is allocated between the categories identified in OAR 860-026-0022(2). Please describe the activities and associated expense (broken out by labor & non-labor) associated with marketing research and sales activities (include fuel switching and retention of customers) that is included in the test year. Please

include references to the testimony and exhibits, and to which FERC and internal utility accounts this expense is booked.

Response:

a. Attachment 104-A, "Cat A Expenses & Cat C Calc" tab, provides Category A advertising expenses included in the 2018 test year by FERC Account. Advertising expenses are billed through customer service Account 9090001.

See also PGE Exhibit 200, work paper "Exhibit Support 2016.xlsx", "Cat A Adv."

b. See PGE's Response to part (a).

c. See PGE's Response to part (a).

d. Attachment 104-A, "Cat A&B 909" tab, Column L, cell L13, provides Category B advertising expenses included in the 2018 test year by FERC Account. Advertising expenses are billed through customer service Account 9090001.

e. PGE has not included costs associated with Category C advertising in the 2018 test year. The exclusion of these costs can be found in PGE Exhibit 200, work paper "Exhibit Support 2018.xlsx", tab "A&G", cell E36.

f. Attachment 104-A, "Cat D 417" tab, provides budgeted 2018 test year advertising expenses not included in base rates. PGE does not have sales activities or marketing research for fuel switching or the retention of customers.

UE 319

Attachment 104-A

Provided in Electronic Format only

March 24, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 169
Dated March 13, 2017

Request:

For any Category advertising expense included in the Test Year revenue requirement that is associated with a promotional activity or a promotional concession program, please provide a summary table that includes:

a. A description of the activity or program, and justification for inclusion into rates;
b. A breakout of the related expense by labor & non-labor; and
c. The FERC and internal utility account to which the expense will be booked and include references to appropriate exhibit pages.

Response:

There are no costs for promotional activities in the 2018 Test Year request. PGE did not budget promotional activities or promotional concessions as defined in OAR 860-026-0010 or OAR 860-026-0015

March 24, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 170
Dated March 13, 2017

Request:

Please identify any other budgeted advertising expense for the test year that will NOT be included in base rates, including below-the-line or non-utility expense, or advertising expense expected to be collected through a tariff.

Response:

See Attachment 170-A.

UE 319

Attachment 170-A

Provided in Electronic Format only

Advertising Expenses
Not in Rates

CASE: UE 319
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 904

Exhibits in Support
Of Opening Testimony

June 16, 2017

February 28, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Standard Data Request No. 089
Dated February 28, 2017

Request:

Provide a schedule showing the contributions and donations included in the utility's regulatory expense accounts for the most recent historical twelve month period by FERC account. Also, provide the amounts included in the projected Test Year expenses.

Response:

In accordance with the Code of Federal Regulations, PGE does not charge charitable contributions and donation amounts to utility regulatory expense accounts. These are charged "below-the-line" to FERC Account 426, and are not included in PGE's proposed revenue requirement for the 2018 test year.

February 28, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Standard Data Request No. 090
Dated February 28, 2017

Request:

Provide a schedule showing all dues (industry organizations, clubs, professional organizations, etc.) included in the utility's regulatory expense accounts for the most recent historical twelve month period by FERC account. Also, provide the amounts included in the projected Test Year expenses.

Response:

The following table provides utility membership costs by FERC account for 2016 actuals, and the 2018 test year forecast.

FERC Account	2016 Actuals	2018 Budget
921	58,519	128,208
926	1,205	3,584
930	3,025,447	3,428,311
Totals	**$3,085,171**	**$3,560,103**

PGE's 2018 membership costs have increased largely due to increased costs for WECC and Peak Reliability as well as the Northern Tier Transmission Group (NTTG). These expenses are booked to remain in FERC Account 930.1, and are discussed in PGE Exhibit 600.

March 27, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Standard Data Request No. 222
Dated March 13, 2017

Request:

Please provide transaction details for all donations, membership fees, included in the Test Year; including references to the appropriate FERC Account.

Response:

PGE does not budget contributions and donations at the transaction level in our Powerplan budgeting system. Powerplan is only able to budget contributions and donations on a summary account level.

See Attachment 222-A, which provides a summary of known or expected contributions and donations including those in the 2018 Test Year, and those that are below the line and not included in rates. This attachment also provides a breakdown of PGE sponsorships that are included in the 2018 test year forecast.

See also PGE's Response to Standard Data Request No. 89. In accordance with the Code of Federal Regulations, PGE does not charge charitable contributions and donation amounts to utility regulatory expense accounts. These are charged "below-the-line" to FERC Account 426, and are not included in PGE's proposed revenue requirement for the 2018 test year.

Note: In preparation of this response PGE discovered entries have inadvertently been classified to incorrect FERC accounts. PGE believes that these amounts are immaterial and will provide a supplemental response by April 5.

UE 319

Attachment 222-A

Provided in Electronic Format only

PGE Contribution List

March 27, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 223
Dated March 13, 2017

Request:

Please provide a list of all memberships and dues, including a description of how they benefit Oregon ratepayers.

Response:

PGE contacted Staff to clarify the question. PGE agreed to provide 2016 Membership Actuals and in addition to provide a summary level description of 2018 membership budgets.

PGE does not budget memberships at the transaction level in our PowerPlan budgeting system. PowerPlan is only able to budget memberships on a summary account level, however PGE expects the 2018 levels to reflect those historically.

See Attachment 223-A, a summary of known or expected memberships included in the 2018 Test Year as we have been able to identify them to date. PGE will continue to explore membership information throughout our departments, and will update the list as new information is identified. Note that while PGE has limited its request for recovery of memberships and dues to approximately $3.5 million, we are providing a list of all known memberships and dues beyond including those charged "below-the-line" to FERC Account 426, and are not included in PGE's proposed revenue requirement for the 2018 test year.

See Attachment 223-B, a list of PGE's 2016 Membership Actuals. Attachment 223-B is protected information and subject to OPUC Protective Order No. 17-057.

PGE's Corporate memberships are budgeted to: CE 2701 Memberships, FERC 930.

PGE's individual memberships are budgeted to: CE 2701 Memberships, FERC 921.

PGE's non-utility and lobbying expenses are budgeted to: CE 2701, FERC 426. FERC accounts 426 is a below the line activities.

UE 319

Attachment 223-A

Provided in Electronic Format only

2018 Budgeted Memberships

UE 319

Attachment 223-B

Provided in Electronic Format only

Protected and subject to OPUC
Protective Order No. 17-057

2016 Actual Memberships

CASE: UE 319
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 905

Exhibits in Support
Of Opening Testimony

June 16, 2017

March 24, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 224
Dated March 13, 2017

Request:

Please indicate which projects listed in Exhibit PGE/604, Lobdell - Tooman/2-21 are likely to be completed, with benefits accruing to PGE customers, no later than December 31, 2018. For each project with benefits not accruing to customers by year-end 2018, provide the date by which PGE estimates benefits will available to customers and PGE.

Response:

PGE Attachment 224-A, Table 1, lists all projects with PGE's best estimates of completion and benefit delivery (i.e., qualitative, quantitative or both) for 2016 or beyond, as most of the projects are multi-year in nature.

For PGE, one of several R&D purposes is to explore promising work or technology; namely to gain experience with the technology and a knowledge base such that we are positioned to implement the technology if and when it becomes cost effective and reliable. In this vein, the short term benefits are creation of technical knowledge and skill sets within PGE to help prepare for a potential future that may evolve. Some technologies (e.g., energy storage in all its forms, including electrochemical, thermal, compressed air, pumped hydro) might be three years away or fifteen years away. To prepare for and maximize the benefits that might derive, PGE seeks to keep current on the various technologies, the associated engineering and the IT systems to implement them. The alternative in not preparing is to potentially implement solutions that are less informed and can be more costly to our customers.

PGE strives to select and perform R&D that yields value and benefits to our customers. In the larger context the attempt is made to quantify or otherwise monetize these benefits. In a narrower context, it is often a challenge to predict with any precision how realistic this quantification can be. For example, in 1998-99 PGE funded an R&D project to test whether a backup 0.25 MW diesel generator in Salem could be started remotely and reliably from Portland. The test was a success and thus, the modest expended funds would be considered beneficially spent on a qualitative basis even though it yielded no immediate quantifiable cost savings. If the test had failed, the derived benefit would have been the acknowledgement that the adopted approach was incorrect or needed to be improved at a next trial if deemed prudent.

The main benefit from that successful test was that it was the first critical step to the evolution of what is now PGE's very successful and innovative dispatchable standby generation (DSG) program. The DSG program now remotely controls nearly 100 MW of backup generators that serve as non-spinning reserve and can be dispatched on a coordinated basis with PGE's Power Operations. Comparative quantitative value can now be realized from:

(1) The non-spinning reserve capacity value

(2) The avoided capital asset cost to provide this service had PGE instead been required to build alternative resource i.e., a fast starting single cycle natural gas fired turbine power plant used for peaking.

Thus, in the narrow context, (i.e., demonstrating remote start capability), the project yielded qualitative value while the continued development DSG led to substantial quantitative value.

The DSG example highlights the fact that some R&D projects may not produce material benefits to customers <u>for a period of years, much less in a quarter</u>. In the DSG example it took several years and a slow build-up of knowledge and confidence before the program reached a noticeable and relevant size. By 2005 the DSG program had grown to 26.5 MW and by 2008 had more than doubled to 70.7 MW. PGE's slow and thoughtful development of the DSG program was delivered (and currently continues) over a period of 15 years. During this time frame, it has been supported by five separate R&D projects to continue to improve and to help diversity the program. These included experiments in using dual fuels, i.e., natural gas and diesel; use of biodiesel instead of petroleum based diesel fuel; and mounting small catalytic converters to reduce undesirable NOx emission.

We discuss two additional projects below that include one or more benefit to PGE customers:

1. <u>OSU – Cascadia Lifelines Research:</u> The Cascadia Lifelines Program will provide essential and unique engineering solutions including cost-effective retrofit strategies for infrastructure subjected to long-duration shaking resulting from a Cascadia Subduction Zone event. The project will provide improved prediction of ground-shaking specific to Oregon conditions, predicted seismic behavior of soils unique to the Willamette Valley, including the liquefaction potential, and system optimization of interdependent lifelines. The impact of this research will help assess cost-effective approaches to increased resilience, resulting in saved lives and improved business continuity for western Oregon and PGE's service territory. In joining this program effort headed by Oregon State University ("OSU"), PGE continues taking a pro-active approach in minimizing the impact of the next devastating earthquake on its customers, and doing its part in improving Oregon's ability to bounce back from such an event. As a secondary benefit,

teaming with OSU on this research gives PGE ready access to the team of seismic hazard mitigation experts at the university. R&D funding is $50,000 per year for a 5-year commitment or $250,000 over five years; PGE occupies a seat on the management board that guides the OSU research priorities. The dollar commitment on behalf of PGE customers is substantially matched from other utility and related infrastructure providers (e.g., BPA, ODOT, NW Natural, EWEB, Port of Portland and others) yielding a match of five to 10 fold.

2. Biomass Supply Chain Development in Support of Boardman Conversion: Since 2009, PGE has investigated the potential to use torrefied biogenic biomass to displace coal at its Boardman Power Plant. This has been coupled to the need to pre-process the biomass through torrefaction in order to make the fuel sufficiently friable (crispy) so that it can be ground to a fine powder in the Boardman pulverizers. PGE has done early exploration in partnership with OSU Extension into a biomass supply chain via energy grass agronomy especially for Arundo and Sorghum. In 2016, PGE worked with Oregon Torrefaction, LLC to explore the availability of woody biomass derived in part, from USFS Forest Stewardship contracts out the Malheur National Forest. As Boardman gets closer to its commitment to cease use of coal at the end of 2020; the study will help PGE to firm its views of what will be the potential biomass supply chain components sufficient to fire the Plant at 30% to 40% capacity.

In summary, many R&D projects do not produce immediate benefits to customers, may take years and are typically not scheduled as quarterly deliverables. R&D is designed as an exploration of work or technology; namely to gain experience with the technology and knowledge base that surrounds so as to be positioned to implement the technology if and when it becomes cost effective and reliable. Consequently, the short term benefits are creation of technical knowledge and skill sets. Some technologies, like energy storage, might be three years away or fifteen years away. PGE believes that on behalf of its customers it is incumbent to keep current on evolving technology, and the engineering and IT systems to implement it so that they can be implemented when practical, cost-effective and reliable.

UE 319

Attachment 224-A

Provided in Electronic Format only

R&D Project Completion Estimates
for 2016 or beyond

ATTACHMENT 224-A

R&D Project Completion Estimates for 2016 or beyond

Project	Will project be completed, with benefits accruing to PGE customers by End of Year 2018?	For each project with benefits not accruing to customers by year-end 2018, provide the date by which PGE estimates benefits will available to customers and PGE
EPRI P69: Maintenance Management & Technology[1]	Yes (project ongoing)	n/a
EPRI P104: Generation Maintenance Applications Center[1]	Yes (project ongoing)	n/a
EPRI Power Quality Knowledge Development and Tranfser[1]	Yes (project ongoing)	n/a
EPRI P64: Boiler and Turbine Steam & Cycle Chemistry[1]	Yes (project ongoing)	n/a
EPRI P68: Instrumentation, Controls & Automation[1]	Yes (project ongoing)	n/a
EPRI P183: Cyber Security[1]	Yes (project ongoing)	n/a
EPRI Program 62 – Occupational Health and Safety[1]	Yes (project ongoing)	n/a
EPRI Program 88 Combined Cycle HRSG and Balance of Plant (3-year)[1]	Yes (project ongoing)	n/a
EPRI P60: EMF and RF Health Assessment & Safety (3-year)[1]	Yes (project ongoing)	n/a
Non-Wires Solutions to Transmission Congestion	Yes	n/a
OIT -- Second Life Battery Research	Yes	n/a
Comparative Studies of Energy Storage: CAES, Batteries, Super Caps - OIT	Yes	n/a
U of O, Regional Solar Radiation Data Center Project	Yes	n/a
Investigate Wake Effects on Biglow Canyon Phase 3 Production	Yes	n/a
OSU -- Cascadia Lifelines Research	Yes	n/a
CEA-2045 EPRI demo of "Smart" water heaters & EVSE (PEV 240V chargers)	Yes	n/a
Low Income City of Portland Multi-Family Heat Pump Water Heater demo	Yes	n/a
EPRI P170: End-Use Energy Efficiency & DR Subset D[1]	Yes	n/a
EPRI P174: Integration of Distributed Energy Resources[1]	Yes	n/a
EPRI P173: Bulk Power Sys. Integration of Variable Generation[1]	Yes	n/a
EPRI Computer Based Training & Modules (CBT) for Sulfur Hexafluoride SF6[1]	Yes	n/a
OSU Real-time Load Modelling OSU's S-Phasor Network, Microgrid Reliability	Yes	n/a

[1] Note regarding EPRI Projects: Many of these efforts are multiyear (ongoing) efforts that have varying benefits—some of which are immediate, others are in the future.

ATTACHMENT 224-A

Staff/905
Zarate/6

R&D Project Completion Estimates for 2016 or beyond

Project	Will project be completed, with benefits accruing to PGE customers by End of Year 2018?	For each project with benefits not accruing to customers by year-end 2018, provide the date by which PGE estimates benefits will available to customers and PGE
Analytical Pilot Study of demand impact forecasting & validation technology	Yes	n/a
EPRI Program 180 – Distribution Systems[1]	Yes	n/a
WSU Power Engineering Energy Innovation Center Data Access	Yes	n/a
EPRI Program 87 Fossil Materials and Repair[1]	Yes	n/a
Smart House Design: PSU-PGE	Yes	n/a
Utility Demonstration Projects & Pilots - Best Practices and Lessons Learned	Yes	n/a
Behind the Meter Use of Energy Storage & a PV System - Customer Behavior	Yes	n/a
EPRI P94: Energy Storage and Distributed Generation[1]	Yes	n/a
Oregon State University Wave Energy Support	No	2019-2021
Collaboration with BPA Innovation Technology Program - up to 15 topics	No	2018-2020
NuScale Modular Reactor Study Group	No	2019-2025
Practicality of 100% Solar Roofing material in the Pacfic NW	No	2019-2021
Exploring use of Digital Personal Assistants to lower utility transaction cost	No	2019-2021
Exploring use of Non-Intrusive Customer Load Monitoring Devices (3-year)	No	2019-2021
Biomass Supply Chain Development in support of Boardman Conversion		
Pre-Feasibility Study - Low Head Hydrokinetic Device		
Load shifting at small scale using HVAC with Ice Storage unit	No	2019-2021
EV Behavior Battery SOC Research (Non PGE Customer Employees)	No	2019-2021
Resiliency Applications of Electric Vehicles in Post Seismic Events (V2G)	No	2019-2021
PSU – Battery Backup Field Demo; residential and grid support	No	2019-2021
Battery Backup Demo of a Public or MUSH Facility	No	2019-2021
Joule Bank System	No	2022 or later
Multi-Family Energy Management (2-year project)	No	2019-2021
Update Regional Appliance load usage database	No	2019-2021
Torrefied Fuel Test Burns Multiple Day Proof of Concept Test	No	2019-2021
Bidding the SSPC into the Energy Imbalance Market (EIM)	No	2019-2021

[1] Note regarding EPRI Projects: Many of these efforts are multiyear (ongoing) efforts that have varying benefits—some of which are immediate, others are in the future.

March 24, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 225
Dated March 13, 2017

Request:

Please indicate which projects listed in Exhibit PGE/604, Lobdell - Tooman/2-21 are likely to lead to average utility rate reductions in the long run, inclusive of the costs of the projects. Provide all applicable work papers in electronic format, with cell references and formulae intact.

Response:

Please see PGE Exhibit 604 and PGE's Response to OPUC Data Request No. 224, Attachment 224-A. Attachment 224-A, Table 1, lists PGE's estimates of when and if these results might be realized. PGE Exhibit 604 and PGE's Response to OPUC Data Request No. 226 identify the R&D project benefit expectations.

PGE's R&D efforts are coordinated by a formal governance committee. PGE believes that all of the R&D projects listed in PGE Exhibit 604 either inform or are applicable to PGE's customers and have the potential to lead to average utility rate reductions inclusive of the costs of the project. In as much as these projects are inherently research and development in nature, they are, in and of themselves, "theoretical." Thus, in order to render the value, we must assume that the projects are successful, or can be carried to sufficient completion so as to yield results, or they provide valuable information that leads to other projects/benefits.

March 27, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 226
Dated March 13, 2017

<u>Request:</u>

On page 14, lines 5-9, of Exhibit PGE/600, Lobdell -Tooman, the Company expresses its desire to more than double its research and development (R&D) expenses in going from 2016 actuals to its 2018 forecast.

a. Please rank the projects (with costs and projected benefits identified) in order of highest priority to lowest priority.

b. Assuming the Commission does not include all requested R&D costs in rates beyond fifty percent above the 2016 actuals; will the Company continue to proceed on all the projects? If not, which projects will the Company consider delaying?

c. Provide total amount cost for each year since last rate case until today. Please provide in excel work sheet.

<u>Response:</u>

Annual R&D expenses of $2.0 million , of which $1.8 million is for specific R&D projects, were previously approved (through OPUC Docket UE 294). PGE filed for an additional $1.0 Million for R&D expenditures in the 2018 Test Year.

a. Attachment 226-A provides PGE's project ranking proposal for the proposed 2018 R&D projects, and impacts of limiting PGE's R&D budget.

b. As has been the case in recent years, PGE typically has more R&D projects under consideration than it has available funds; thus, projects <u>not listed</u> in Attachment 226-A, will likely be postponed to later years. PGE's current steering committee guidance is that PGE will not proceed to fund a project if the allowed amount is significantly different than the forecasted expenditure. If PGE does not receive the funds to include all requested R&D, then PGE would only fund the projects up to the allowed amount.

c. Attachment 226-B provides the total expenditures since PGE's last general last rate case through February, 2017 (PGE's last accounting cycle update).

PGE receives proposals for new R&D projects throughout any given year. The R&D Steering Committee is responsible for reviewing each proposal and ranking them in terms of priority. Project reviews occur annually with quarterly updates to accommodate changes to projects as they arise. Attachment 226-A, identifies the highest priority R&D projects that are scheduled to begin in 2017 or 2018. These are inclusive of the projects identified in PGE Exhibit 604 and PGE's Response to OPUC Data Request No. 224.

Detailed benefits for all proposed projects are included in UE 319/ PGE/604. Many of these R&D projects have several benefits. We provide examples below of projects that include one or more benefit to PGE customers:

1. <u>OSU – Cascadia Lifelines Research:</u> The Cascadia Lifelines Program will provide essential and unique engineering solutions including cost-effective retrofit strategies for infrastructure subjected to long-duration shaking resulting from a Cascadia Subduction Zone event. The project will provide improved prediction of ground-shaking specific to Oregon conditions, predicted seismic behavior of soils unique to the Willamette Valley, including the liquefaction potential, and system optimization of interdependent lifelines. The impact of this research will help assess cost-effective approaches to increased resilience, resulting in saved lives and improved business continuity for western Oregon and PGE's service territory. In joining this program effort headed by Oregon State University ("OSU"), PGE continues taking a pro-active approach in minimizing the impact of the next devastating earthquake on its customers, and doing its part in improving Oregon's ability to bounce back from such an event. As a secondary benefit, teaming with OSU on this research gives PGE ready access to the team of seismic hazard mitigation experts at the university. R&D funding is $50,000 per year for a 5-year commitment or $250,000 over five years; PGE occupies a seat on the management board that guides the OSU research priorities. The dollar commitment on behalf of PGE customers is substantially matched from other utility and related infrastructure providers (e.g., BPA, ODOT, NW Natural, EWEB, Port of Portland and others) yielding a match of five to 10 fold.

2. <u>Biomass Supply Chain Development in Support of Boardman Conversion</u>: Since 2009, PGE has investigated the potential to use torrefied biogenic biomass to displace coal at its Boardman Power Plant. This has been coupled to the need to pre-process the biomass through torrefaction in order to make the fuel sufficiently friable (crispy) so that it can be ground to a fine powder in the Boardman pulverizers. PGE has done early exploration in partnership with OSU Extension into a biomass supply chain via energy grass agronomy especially for Arundo and Sorghum. In 2016, PGE worked with Oregon Torrefaction, LLC to explore the availability of woody biomass derived in part, from USFS Forest Stewardship contracts out the Malheur National Forest. As Boardman gets closer to its commitment to cease use of coal at the end of 2020; the study will help PGE to firm its views of what will be the potential biomass supply chain components sufficient to fire the Plant at 30% to 40% capacity.

UE 319

Attachment 226-A

Provided in Electronic Format only

R&D Project Ranking

UE 319

Attachment 226-B

Provided in Electronic Format only

R&D Actuals
Post UE 294

Attachment 226-A
PGE R&D Project Ranking (2018 proposal)

Project	Rank (1 = highest priority)	Benefit Type[1]	2018 Proposed Project Budget (UE 319/PGE/ 604 Lobdell – Tooman)	Cumulative 2018 Proposed Project Budget (UE 319/PGE/ 604 Lobdell – Tooman)	Project Delayed if Funding Limited to 50% above 2016 Actuals (Y/N)
EPRI P174: Integration of Distributed Energy Resources	1	S, RL, RPS, E	$ 40,000	$ 40,000	No
OSU - Cascadia Lifelines Research	2	RS	$ 50,000	$ 90,000	No
EPRI Program 180 – Distribution Systems	3	E, RL	$ 170,000	$ 260,000	No
EPRI P183: Cyber Security	4	RL, RS, E, C	$ 95,000	$ 355,000	No
EPRI Power Quality Knowledge Development and Transfer	5	E	$ 30,000	$ 385,000	No
EPRI P173: Bulk Power Sys. Integration of Variable Generation	6	E, RPS, RL	$ 75,000	$ 460,000	No
EPRI Program 62 – Occupational Health and Safety	7	S	$ 50,000	$ 510,000	No
Oregon State University Wave Energy Support	8	L, RS	$ 30,000	$ 540,000	No
U of O, Regional Solar Radiation Data Center Project	9	RPS, RL, E	$ 10,000	$ 550,000	No
NuScale Modular Reactor Study Group	10	S, RS	$ 5,000	$ 555,000	No
Non-Wires Solutions to Transmission Congestion	11	E, RL	$ 25,000	$ 580,000	No
WSU Power Engineering Energy Innovation Center Data Access	12	RL, RS	$ 25,000	$ 605,000	No
PSU – Battery Backup Field Demo; residential and grid support	13	E, RL, S, CE	$ 40,000	$ 645,000	No
CEA-2045 EPRI demo of "Smart" water heaters & EVSE (PEV 240V chargers)	14	E, RL, CE	$ 40,000	$ 685,000	No
OSU Real-time Load Modelling OSU's S-Phasor Network, Microgrid Reliability	15	E, RL	$ 35,000	$ 720,000	No
Biomass Supply Chain Development in support of Boardman Conversion	16	RPS	$ 110,000	$ 830,000	No
EPRI P94: Energy Storage and Distributed Generation	17	S, RL, RPS, E	$ 100,000	$ 930,000	No
Torrefied Fuel Test Burns Multiple Day Proof of Concept Test	18	RPS	$ 300,000	$ 1,230,000	No
Collaboration with BPA Innovation Technology Program - up to 15 topics	19	RS, E	$ 100,000	$ 1,330,000	No
OIT -- Second Life Battery Research	20	E	$ 35,000	$ 1,365,000	No
EPRI P60: EMF and RF Health Assessment & Safety (3-year)	21	S	$ 146,000	$ 1,511,000	No
EPRI P69: Maintenance Management & Technology	22	S, E	$ 72,000	$ 1,583,000	No
Smart House Design: PSU-PGE	23	CE, E	$ 10,000	$ 1,593,000	No
Comparative Studies of Energy Storage: CAES, Batteries, Super Caps - OIT	24	E, RL	$ 35,000	$ 1,628,000	No
EPRI P104: Generation Maintenance Applications Center	25	S, E	$ 40,000	$ 1,668,000	No
EPRI Program 88 Combined Cycle HRSG and Balance of Plant (3-year)	26	E	$ 68,000	$ 1,736,000	No
Battery Backup Demo of a Public or MUSH Facility	27	RS, RL, E, CE	$ 100,000	$ 1,836,000	No
Investigate Wake Effects on Biglow Canyon Phase 3 Production	28	RPS	$ 20,000	$ 1,856,000	No
EPRI P64: Boiler and Turbine Steam & Cycle Chemistry	29	E	$ 30,000	$ 1,886,000	No
EPRI P68: Instrumentation, Controls & Automation	30	E	$ 47,000	$ 1,933,000	No
EPRI P170: End-Use Energy Efficiency & DR Subset D	31	CE	$ 5,000	$ 1,938,000	No
Behind the Meter Use of Energy Storage & a PV System - Customer Behavior	32	RS, RL, E, CE	$ 75,000	$ 2,013,000	No

[1] RS – Resiliency, RL-Reliability, S – Safety, E – operational efficiency (i.e. smart grid), CE – customer engagement, RPS – relates to Renewable Portfolio Standard, C - Compliance

UE 319 PGE Response to OPUC Data Request No. 226
Attachment 226-A
March XX, 2017
Page 2

Attachment 226-A
PGE R&D Project Ranking (2018 proposal)

Project	Rank (1 = highest priority)	Benefit Type[1]	2018 Proposed Project Budget (UE 319/PGE/ 604 Lobdell – Tooman)	Cumulative 2018 Proposed Project Budget (UE 319/PGE/ 604 Lobdell – Tooman)	Project Delayed if Funding Limited to 50% above 2016 Actuals (Y/N)
Utility Demonstration Projects & Pilots - Best Practices and Lessons Learned	33	E, CE	$ 30,000	$ 2,043,000	No
EPRI Program 87 Fossil Materials and Repair	34	E	$ 50,000	$ 2,093,000	No
Bidding the SSPC into the Energy Imbalance Market (EIM)	35	E	$ 15,000	$ 2,108,000	No
EV Behavior Battery SOC Research (Non PGE Customer Employees)	36	CE	$ 30,000	$ 2,138,000	No
Analytical Pilot Study of demand impact forecasting & validation technology	37	E	$ 125,000	$ 2,263,000	No
Update Regional Appliance load usage database	38	E, CE	$ 120,000	$ 2,383,000	No
Pre-Feasibility Study - Low Head Hydrokinetic Device	39	E	$ 25,000	$ 2,408,000	No
Multi-Family Energy Management (2-year project)	40	CE	$ 60,000	$ 2,468,000	No
Low Income City of Portland Multi-Family Heat Pump Water Heater demo	41	E	$ 30,000	$ 2,498,000	No
Exploring use of Non-Intrusive Customer Load Monitoring Devices (3-year)	42	CE, E	$ 40,000	$ 2,538,000	No
Load shifting at small scale using HVAC with Ice Storage unit	43	E	$ 60,000	$ 2,598,000	No
Practicality of 100% Solar Roofing material in the Pacfic NW	44	RPS	$ 40,000	$ 2,638,000	No
Exploring use of Digital Personal Assistants to lower utility transaction cost	45	E	$ 40,300	$ 2,678,300	No
Resiliency Applications of Electric Vehicles in Post Seismic Events (V2G)	46	RS, CE	$ 25,000	$ 2,703,300	No
Joule Bank System	47	E, RS	$ 40,000	$ 2,743,300	No
EPRI Computer Based Training & Modules (CBT) for Sulfur Hexafluoride SF6	48	S	$ 10,000	$ 2,753,300	Yes

March 27, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 227
Dated March 13, 2017

Request:

Referring to Exhibit PGE/604, Lobdell - Tooman/2-21, please indicate which projects are, in PGE's view, applicable solely to PGE and for which studies done elsewhere in the Company would not otherwise inform or be applicable to PGE's customers.

Response:

PGE interprets Staff's intended question to be 'elsewhere in the *country'*, not 'company'. See Attachment 227-A for a list of projects and studies PGE considers to be solely applicable to PGE customers.

PGE looks to leverage its R&D expenditures whenever possible and a prime example are expenditures related to Electric Power Research Institute (EPRI) programs and projects. EPRI was originally formed to allow utilities to pool R&D type expenditures in areas of common interest. Partnerships with universities, national labs and other regional entities like the BPA are other examples of shared investments where PGE's expenditures are highly leveraged and often constitute a small fraction of the total investment (e.g., OSU Cascadia Lifelines Research, Collaboration with BPA Innovation Technology Program). In some cases, research needs are unique to PGE. Programs examples where PGE has assumed a leadership position include: Dispatchable Standby Generation, Salem Smart Power Center, and Electric Vehicles; and projects that are unique to PGE infrastructure such as Boardman Biomass. In other instances, such as the PSU Battery Backup Field Demonstration Project, the research is intended to provide hands-on experience with emerging technologies that will benefit customers upon broad-scale deployment.

UE 319

Attachment 227-A

Provided in Electronic Format only

R&D Projects Solely Applicable to PGE

ATTACHMENT 227-A

R&D Projects and Studies

Project	Projects and Studies considered solely applicable to PGE?
EPRI P69: Maintenance Management & Technology	
EPRI P104: Generation Maintenance Applications Center	
EPRI Power Quality Knowledge Development and Transfer	
EPRI P64: Boiler and Turbine Steam & Cycle Chemistry	
EPRI P68: Instrumentation, Controls & Automation	
EPRI P183: Cyber Security	
EPRI Program 62 – Occupational Health and Safety	
EPRI Program 88 Combined Cycle HRSG and Balance of Plant (3-year)	
EPRI P60: EMF and RF Health Assessment & Safety (3-year)	
Non-Wires Solutions to Transmission Congestion	Yes
OIT -- Second Life Battery Research	Yes
Comparative Studies of Energy Storage: CAES, Batteries, Super Caps - OIT	Yes
U of O, Regional Solar Radiation Data Center Project	
Investigate Wake Effects on Biglow Canyon Phase 3 Production	Yes
OSU -- Cascadia Lifelines Research	
CEA-2045 EPRI demo of "Smart" water heaters & EVSE (PEV 240V chargers)	.
Low Income City of Portland Multi-Family Heat Pump Water Heater demo	Yes
EPRI P170: End-Use Energy Efficiency & DR Subset D	
EPRI P174: Integration of Distributed Energy Resources	
EPRI P173: Bulk Power Sys. Integration of Variable Generation	
EPRI Computer Based Training & Modules (CBT) for Sulfur Hexafluoride SF6	
OSU Real-time Load Modelling OSU's S-Phasor Network, Microgrid Reliability	
Analytical Pilot Study of demand impact forecasting & validation technology	Yes
EPRI Program 180 – Distribution Systems	
WSU Power Engineering Energy Innovation Center Data Access	
EPRI Program 87 Fossil Materials and Repair	
Smart House Design: PSU-PGE	Yes
Utility Demonstration Projects & Pilots - Best Practices and Lessons Learned	
Behind the Meter Use of Energy Storage & a PV System - Customer Behavior	Yes
EPRI P94: Energy Storage and Distributed Generation	
Oregon State University Wave Energy Support	
Collaboration with BPA Innovation Technology Program - up to 15 topics	
NuScale Modular Reactor Study Group	
Practicality of 100% Solar Roofing material in the Pacific NW	Yes
Exploring use of Digital Personal Assistants to lower utility transaction cost	
Exploring use of Non-Intrusive Customer Load Monitoring Devices (3-year)	Yes

ATTACHMENT 227-A R&D Projects and Studies	
Project	**Projects and Studies considered solely applicable to PGE?**
Biomass Supply Chain Development in support of Boardman Conversion	Yes
Pre-Feasibility Study - Low Head Hydrokinetic Device	Yes
Load shifting at small scale using HVAC with Ice Storage unit	Yes
EV Behavior Battery SOC Research (Non PGE Customer Employees)	Yes
Resiliency Applications of Electric Vehicles in Post Seismic Events (V2G)	Yes
PSU – Battery Backup Field Demo; residential and grid support	Yes
Battery Backup Demo of a Public or MUSH Facility	Yes
Joule Bank System	Yes
Multi-Family Energy Management (2-year project)	Yes
Update Regional Appliance load usage database	
Torrefied Fuel Test Burns Multiple Day Proof of Concept Test	Yes
Bidding the SSPC into the Energy Imbalance Market (EIM)	Yes

CASE: UE 319
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1000

Opening Testimony

June 16, 2017

Q. Please state your name, occupation, and business address.

A. My name is Ming Peng. I am a Senior Economist employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1001.

Q. What is the purpose of your testimony?

A. I discuss my analysis of the depreciation expense and accumulated depreciation, or depreciation reserve, portions of PGE's (PGE or Company) revenue requirement for this rate case as documented by the Company witnesses in PGE/200, Tooman-Brown.

Q. Did you prepare an exhibit for this docket?

A. Only my witness qualification statement.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1: ANALYSIS OF DEPRECIATION FROM A RATEMAKING PERSPECTIVE

Q. What is depreciation?

A. "Depreciation" is defined by the National Association of Regulatory Utility Commissioners (NARUC) in relevant part as follows:

> As applied to the depreciable plant of utilities, the term depreciation means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes that are known to be in current operation, against which the company is not protected by insurance, and the effect of which can be forecast with reasonable accuracy. Among the causes to be considered are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirement of public authorities.[1]

The statement above defines "depreciation" from a valuation perspective. From an accounting perspective, "depreciation" is the allocation of the cost of fixed assets less net salvage to accounting periods, which is a capital recovery concept. From a ratemaking perspective, both the valuation (rate base) and accounting (capital recovery) concepts of deprecation are important.

Q. Do Oregon statutes address utility depreciation rates?

A. Yes. ORS 757.140(1) states:

> Every public utility shall carry a proper and adequate depreciation account. The Public Utility Commission shall ascertain and determine the proper and adequate rates of

[1] NARUC, Public Utility Depreciation Practices p.318 (1996).

> depreciation of the several classes of property of each public utility. The rates shall be such as will provide the amounts required over and above the expenses of maintenance, to keep such property in a state of efficiency corresponding to the progress of the industry. Each public utility shall conform its depreciation accounts to the rates so ascertained and determined by the commission. The commission may make changes in such rates of depreciation from time to time as the commission may find to be necessary.

Q. How are depreciation rates determined?

A. To develop depreciation rates, it is necessary to estimate (1) the combination of survivor curve-service life (Curve-Life) of utility property, and (2) net salvage (Gross Salvage – Cost of Removal) ratio. Based on these two fundamental depreciation parameters (and other required elements, such as asset value, asset remaining life, and depreciation method) the depreciation rates are derived.

Q. What depreciation rates did PGE use in its Test Year revenue requirement?

A. PGE filed its new depreciation study on December 23, 2016. The depreciation rates used in this rate case filing are currently under the Commission review. [2] PGE expected effective date for new depreciation rates is January 1, 2018.

Q. How much does PGE's 2018 depreciation expense increase compared to 2016 actuals?

A. PGE asks $317.4 million in depreciation expense for 2018. PGE's total forecasted depreciation for 2018 reflects a $40.1 million increase over

[2] Docket No. UM 1809.

2016 actuals. $2 million out of $40.1 million increase is due to change of depreciation rates.

Q. What are the primary drivers for the increase?

A. PGE explains that the primary drivers of the increase in depreciation expense are:

- $4.4 million for the Colstrip generation plant to reflect the change of depreciable life from 2042 to 2030 as specified in Oregon Senate Bill 1547, Section 1.
- $6.8 million for the Carty generation plant, which had only partial year depreciation in 2016 but a full year in 2018. Customer prices, however, already reflect the full year of Carty 2016 depreciation expense in accordance with Commission Order No, 15-356.
- $4.0 million in other thermal generating plants
- $4.7 million in wind and hydro generation resources
- $6.4 million in distribution
- $3.5 million in general plant

Q. How did you analyze the Company's proposed depreciation expense, and what information did you review?

A. To confirm that the depreciation expense was properly calculated, the Staff reviewer should use the authorized depreciation parameters established by the Commission in connection with its review of utility depreciation studies. As noted above, PGE filed its most recent Depreciation Study on December 23, 2016, and it is in process, so updated depreciation rates are not yet available. Staff's review focuses on some calculations of depreciation expense and the primary drivers for depreciation expense increase.

ISSUE 2: DEPRECIATION EFFECT ON REVENUE REQUIREMENT

Q. Describe the depreciation effect on the revenue requirement of a utility.

A. In the traditional rate base rate-of-return environment, rate base and utility costs are components of a utility's revenue requirement. NARUC, in its "Public Utility Depreciation Practices" manual on "Depreciation Expense and Its Effect on the Utility's Financial Performance – Revenue Requirement" states:

> Depreciation has a profound effect on the revenue requirement of a utility, and for many utilities, depreciation expense represents a large percentage of total operating expenses. In addition, deferred income taxes, rate base, and cost of capital are all affected by the depreciation practices of a utility.[3]

Q. What is the relationship between depreciation and revenue requirement?

A. Under cost of service regulation, revenue requirement refers to the revenues the utility must earn to recover the cost of providing service and to earn a reasonable return on its investment. To compute the revenue requirement (RR) (RR is measured by cost-of-service), a basic formula is followed[4]:

RR = O&M Expense + "Depreciation" + Taxes + Return% x Rate Base

Rate Base = Gross Plant – "Accumulated Depreciation" – Accumulated Deferred Income Taxes + Working Capital

[3] NARUC, Public Utility Depreciation Practices p.195 (1996).
[4] Federal Energy Regulatory Commission, Cost-of-Service Rates Manual p. 6-7 (1999), www.ferc.gov/industries/gas/gen-info/cost-of-service-manual.doc

In this formula, “depreciation” is one of the largest line items in the cost of service; therefore, “depreciation” is important as both an annual expense and as a reduction of rate base.

Q. How are depreciation parameters used in determining the utility’s revenue requirement?

A. In a general rate case filing, the depreciation expense is calculated by using the Commission’s authorized depreciation parameters, from which depreciation rates are derived, and traditional FERC classification of generation, transmission, distribution, and general plant assets.

Accumulated depreciation is the cost of the investment in gross plant that is recovered through the cost-of-service as depreciation expense. Accordingly, the depreciation expense is accumulated and is subtracted from the gross plant to reduce the remaining investment to be recovered. The remaining balance is the Net Book Plant. The net book plant represents the portion of gross plant that is not depreciated.

Q. Have you proposed any adjustment on PGE’s depreciation expense in UE 319 rate case filing?

A. No. The depreciation adjustment needs to wait until the Commission adopts new depreciation rates. The depreciation case of Docket No. UM 1809 is currently under review. The calculation will include both “depreciation expense” and “accumulated depreciation”. Because of depreciation has a profound effect on the revenue requirement, therefore, the Total Operating Expenses, Deferred Income Taxes, Rate Base, Cost of Capital are all affected by the depreciation.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 319
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1001

Witness Qualifications Statement

June 16, 2017

WITNESS QUALIFICATIONS STATEMENT

NAME: Ming Peng (Ms.)

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Energy Rates, Finance and Audit Division

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION & TRAINING:
M.S. Applied Economics
University of Idaho, Moscow

B.S. Statistics
People's University of China, Beijing

C.R.R.A. Certified Rate of Return Analyst
Society of Utility and Regulatory Financial Analysts

Depreciation studies - the Society of
Depreciation Professionals

NARUC Annual Regulatory Studies Program
Michigan State University, East Lansing

300+ credit hours on 30+ topics trainings in public utility industry

EXPERIENCE: 1/11/1999-Present, Public Utility Commission of Oregon

I have been employed by the Public Utility Commission of Oregon (Commission) for 18 years since January 1999. My roles include:
Expert Witness, Case Manager, Economist, Policy Analyst, Econometrician, and Principal Analyst
I have testified in various formal state hearings and performed numerous analyses including economic, financial, statistical, mathematical, marketing, and policy analyses in public utility industry.

Principal Analyst & Case Manager, Settlement Leader/Negotiator for Depreciation and Ratemaking:
For the "Depreciation Rate Determination" (fixed cost allocation, capital recovery), I have served as a Principal Analyst and Case Manager for the

determination of Energy Property Depreciation Rates (Oregon Revised Statute 757.140) for past 10 years.

In this position, I investigate, analyze and calculate “Energy Asset Retirement Cost & Impact” and “Power Plant Decommissioning Cost & Impact” on Customer Rates. I review, calculate, analyze fixed asset depreciation and propose depreciation parameters for each of FERC accounts on Generation, Transmission, Distribution, General, and Coal Mining Plants. The energy sources I have worked on are Steam/Coal, Hydraulic, Natural Gas, Wind, Solar and Geothermal.

My analyses of “Power-Plant-Shutdown” activities include the following cases:

1. PGE closes Boardman Coal-fired plant (UM 1679 & UE 215),
2. PacifiCorp closes Carbon Coal Plant in Utah (UE 246)
3. Multi-state PacifiCorp Klamath Hydro Dam Removal Cost recovery for (1) J. C. Boyle Dam, (2) Copco 1 Dam, (3) Copco 2 Dam, and (4) Iron Gate Dam removal under the ORS 757.734 - Recovery of investment in Klamath River dams in OPUC UE 219.
4. Idaho Power Valmy Coal-fired power plant Shutdown (UE 316)
5. PGE Colstrip Coal-fired power plant Shutdown (UM 1809)

I conduct case investigation and analysis on Utility’s filings, make rate adjustments, lead settlement negotiation, prepare testimony, and appear on behalf of the Commission. The energy companies I work with are: (1) PacifiCorp (serves 6 states), (2) PGE, (3) Northwest Natural Gas (NWN), (4) Idaho Power, (5) Avista Corp (Washington), and (6) Cascade Gas (CNG, Montana).

Lead Analyst and Case Manager on Financial Dockets:

Prior to my present position, I was a lead analyst and case manager for cost of capital, mainly debt capital analysis for nine years. My responsibilities included: review and analyze regulatory policy on Cost of Capital and Market Risks from utility’s financial applications for their Derivative Instruments & Hedging Activities and Capital Raising Activities.

I advised the Commission on over 60 Financial Dockets and obtained the Commission Orders.

I passed the certification test offered by “Society of Utility and Regulatory Financial Analysts”, become a “Certified Rate of Return Analyst” in 2002.

Public Utility & Policy Analyst:

Energy Merger & Acquisition: I have testified in formal state hearings involving Energy Merger & Acquisition, I conducted Acquisition Premiums & Credit Risk Analysis and testified for the Merger case of “PacifiCorp vs. MidAmerican Energy Company” (a subsidiary of Berkshire Hathaway

Energy) in UM 1209. My reviews on Energy Merger & Acquisition also include “PacifiCorp vs. Scottish Power”, “PGE vs. Enron".

Clean Energy – Dollar Impact on Customer Rates: I performed analyses of “Rate Impact Calculation of Oregon Clean Energy Capital Investment, Comparative Advantage of Oregon Clean Energy – Dollar Impact in Rates”.

General Rate Case Ratemaking (Revenue requirement) and Other Cases: I testified and conducted analyses on some subjects in the revenue requirement models for General Rate Cases. I testified on Fuel Price Forecasting regarding Property Sales; I reviewed Load Forecasting, Weather Normalization in “Integrated Resource Planning” (IRP) and Rate Case filing.

My work functions have also included the Statistical Sampling Design & Procedure Design, and I testified on Revenue Issues (UM 1288) by presenting the sampling results.

I conducted Energy Utility Auditing for cost of capital component on energy companies and also preformed utility operational auditing. I have conducted “Interest Rate and Late Payment Charge” Survey and Analysis annually for state of Oregon (UM 779).

I conducted Telecommunications “Market Competition and Economic Policy Survey Analysis” and write report for House Bill 2577, the report has been published on OPUC web annually for 15 years.

Mentor in the ICER - International Confederation of Energy Regulators

I was selected to act as a mentor in the ICER (International Confederation of Energy Regulators) Women in Energy (ICER WIE) pilot mentoring program. My “Mentoring Topics” were focus on Incentive Regulation; Rate and Economic Impacts of “Cost-of-Service” regulation in US and “Price-Cap” in Europe; Cost of Capital, Energy Demand and Price Forecasting Models; Least Cost Planning; and Regulatory Policy & Renewable Energy issues affecting Utility Rates.

CASE: UE 319
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1100

Opening Testimony

<u>REDACTED</u>
June 16, 2017

Q. Please state your name, occupation, and business address.

A. My name is Mitchell Moore. I am a Senior Utility Analyst employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1101.

Q. What is the purpose of your testimony?

A. I am responsible for reviewing the capital plant additions that PGE proposes to include in rate base in this case. I also review the Company's Information Technology projects, including PGE's multi-year Customer Engagement Transformation (CET) project. I address the Company's request for additional full-time equivalent (FTE) positions in the Information Technology, Information Security and Transmission and Distribution divisions.

For reasons explained in more detail below, I recommend removing $64.3 million in capital additions; a reduction of $10.9 million in O&M expense related to CET; a reduction of 23 incremental FTE positions in the IT/IS division and a reduction of 69 FTE positions in the Transmission and Distribution division.

Q. Did you prepare exhibits for this docket?

A. Yes. I prepared the following exhibits:

- Exhibit Staff/1101 – Qualifications Exhibit
- Exhibit Staff/1102 – PGE Response to Staff DR No. 139, Attachment A, excel file.
- Exhibit Staff/1103 – PGE Response to Staff DR No. 489 – Consultant review of CIS & MDM replacement CET project. Confidential

- Exhibit Staff/1104 – Company Response to Staff DR No. 623 – 2017 & 2018 O&M Budget memoranda.
- Exhibit Staff/1105 – Company Response to Staff DR Nos. 481, 504-523, 558.
- Exhibit Staff/1106 – Company Response to Staff DR No. 139 Attachment B, Confidential

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1: CAPITAL ADDITIONS

Q. Please summarize PGE's filing regarding capital additions.

A. PGE anticipates spending approximately $465 million in capital additions in 2017,[1] with an expected year-end rate base of $4,594 million.[2] The approved rate base in the previous general rate case, UE 294, was $4,440 million at year-end 2015. The requested rate base in this case of $4,594 million at year-end 2017 reflects a 3.46 percent increase over two years from year-end 2015. The increase is primarily driven by growth in new-customer connections, as well as projects to upgrade aging infrastructure to better prepare the power grid for earthquakes, cyber-attacks, and other threats.[3] The Company is also replacing or upgrading equipment near the end of its life to ensure continued reliability.[4]

Q. Please describe your review of PGE's capital additions.

A. Staff reviewed the Company's response to Staff Data Requests (DRs) 139 and 140, in which PGE provided a list of all projects that were completed in 2016 and all projects that are expected to be complete by year-end 2017. For projects over $1 million, Staff reviewed the documentation that PGE relied upon to approve funding for the projects.

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[1] Staff/1102, Moore/1 (PGE's response to Staff DR 139, Attachment A, excel file).
[2] PGE/200, Tooman-Brown/14.
[3] PGE/800, Nicholson-Bekkedahl/4-8.
[4] PGE/800, Nichol-Bekkedahl/3.

Q. What is Staff's standard practice in reviewing capital additions for inclusion in rate base?

A. In accordance with ORS 757.355, Staff recommends recognition of plant additions that are placed in service prior to the rate-effective date in this case. In that regard, Staff looks at the timing of plant additions as well as the management and cost of the projects themselves.

Q. What do you conclude from your review of PGE's capital additions?

A. I conclude that the Company's proposed capital spending is generally, but not entirely, prudent and adequately documented. The Company has a centralized project justification system in which yearly spending levels for each project are adequately discussed. PGE also generally does a good job of including analyses of alternatives to going forward with each of the projects. Project documentation includes a description and scope of the proposed projects, discussion of why the current state is not adequate, alternatives that were considered, on-going cost savings and efficiencies, benefits of the project, any other issues or impacts to the organization that the project would entail, as well as discussion of risks, dependencies and constraints.

Q. Are there any projects that Staff questions whether they will be in-service by the rate-effective date?

A. Yes. There is a total of $64.3 million in capital costs that PGE projects will be transferred to plant in December 2017.[5] There are no projected transfers

[5] Staff/1102, Moore/1 (PGE's response to Staff DR 139, Attachment A, excel file).

to plant for any of these projects before December 2017, which indicates these are discrete projects that the Company hopes to have in-service by the end of the year. These 21 projects raise two issues: first, Staff has no evidence that these large projects will actually be complete and in-service by the time rates go into effect. Second, Staff would not have the opportunity to review the spending on the projects and enter evidence into the record before rates go into effect.

Q. What does Staff recommend with regard to these projects?

A. I recommend the $64.3 million be removed from recovery in this case, without prejudice.

Q. Does Staff have any recommendations with regard to capital projects as a whole?

A. Yes. Staff has two recommendations for the Commission. First, I recommend that a PGE officer provide an attestation for any project over $2.5 million that are in-service as of the date that rates will go into effect.

Second, Staff recommends the Commission reserve the right in a future case to review final costs for prudence for projects whose in-service date is after the hearing scheduled in this proceeding. While Staff has reviewed the budgets and expectations of projected costs and recommends Commission approval for the stated amounts with officer attestations, the closing of plant after the hearing in this proceeding means that Staff and other parties have no ability to review closing expenditures to determine whether an adjustment is warranted. In light of the cost-overruns with Carty, Staff recommends the Commission explicitly hold out that a final review of projected plant in rates following the closure of the record are subject to review in a subsequent rate proceeding.

Q. Does Staff have any other concerns related to PGE's capital projects?

A. Yes. Although PGE is not requesting recovery of the bulk of capital costs for its Customer Engagement Transformation (CET) program in this case, as described more fully below, Staff is concerned about the ballooning of costs absent documentation of any change in scope being warranted and the program being prudently managed.

ISSUE 2: CUSTOMER ENGAGEMENT TRANSFORMATION PROGRAM

Q. Please describe PGE's Customer Engagement Transformation (CET) program.

A. PGE states that the CET program is a "comprehensive multiyear program (i.e. 2014-2018) comprised of 24 projects focused on operational efficiencies, process improvements, employee development, business strategies, customer strategies, and the replacement of two large computer systems: Customer Information System (CIS); and Meter Data Management System (MDMS)."[6]

Q. What are Staff's concerns with regard to the CET program?

A. The scope of the project has increased to the point where capital costs have doubled from initial estimates. When the project was first presented to the Commission in UE 262, the CET program was projected to cost between $22 million and $25 million in O&M development expenses and between $70 million and $80 million in capital spending.[7] The Company also projected annual ongoing net O&M reductions of between $4 million and $6 million.[8] In this case, PGE now estimates that capital costs will at least double from initial estimates to approximately $140 million; development O&M expenses are projected to increase to $27.5 million.[9] Notably, the Company no longer

[6] PGE/900, Stathis-Dillin/7.
[7] UE 262 – PGE/900, Stathis-Dillin/12.
[8] UE 262 – PGE/900, Stathis-Dillin/12.
[9] PGE/900, Stathis-Dillin/13.

cites to O&M reductions achieved through efficiencies as a benefit to the program.[10]

Staff previously acknowledged PGE's need to replace outdated systems that are no longer supported by product vendors and are difficult and costly to maintain, and supported cost-recovery for the CET program in previous rate cases.[11] Staff continues to acknowledge this need, and generally supports PGE's plan to replace these systems with updated systems that provide more functionality. However, Staff is concerned about the escalation of the cost, the prudency of which does not appear to be adequately documented in this case.

In 2014, PGE's board approved an estimate of **[BEGIN CONFIDENTIAL]** $[redacted] **[END CONFIDENTIAL]** in capital and **[BEGIN CONFIDENTIAL]** $[redacted] **[END CONFIDENTIAL]** in development expense.[12] That estimate was revised in 2015 to **[BEGIN CONFIDENTIAL]** $[redacted] **[END CONFIDENTIAL]** in capital and **[BEGIN CONFIDENTIAL]** $[redacted] **[END CONFIDENTIAL]** in expense.[13] As stated above, the current estimate presented in this case is $140 million in capital and $27.5 million in expense.

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[10] PGE/900, Stathis-Dillin/12-13.
[11] UE 262 – Staff/100, Wittekind/3 (settled prior to Staff Opening Testimony); UE 283 - Staff/100, Gardner/6 and Second Partial Stipulation (Staff found a substantial increase in expense related to PGE's CET program, but settled with no adjustment).
[12] Staff/1103, Moore/7 (PGE Response to Staff DR 489, Confidential Attachment B).
[13] Staff/1103, Moore/7 (PGE Response to Staff DR 489, Confidential Attachment B).

Q. Why have PGE's costs for the CET program increased?

A. Staff asked a multi-part data request seeking to understand the reasons for the escalation in cost, including a request for all the memoranda, studies, documents and analysis that PGE relied upon to determine that it should move forward with the project.[14] PGE's response included only a summary presentation by a third-party consultant –Emtec – that was hired to review the project and PGE's proposed budget, and a board meeting presentation in October of 2015.

The third-party consultant summary indicates that**[BEGIN CONFIDENTIAL]** "[redacted]." **[END CONFIDENTIAL]** However, either Staff has a different idea of what constitutes a **[BEGIN CONFIDENTIAL]** "[redacted]" **[END CONFIDENTIAL]** to develop a business case than the third-party consultant does, or PGE chose not to share the information with Staff. The project justification form, unlike most of the other projects Staff reviewed, does not contain extensive discussion or analysis, or specific reasons for the escalation in costs.[15] It is minimal and contains high-level information that does not enable Staff to judge the prudency of the proposed increase in cost.

PGE states that the initial cost estimates were made before it had begun negotiations with a vendor and identified the software systems that would be

[14] Staff/1103, Moore/1-4 (PGE Response to Staff DR 489).
[15] Staff/1102, Moore/1 (PGE Response to Staff DR 139).

needed.[16] It also appears that the scope of the project increased over time as PGE identified additional functionality that it wanted – such as integrating the Company's website with the CIS data structure, integration with the company's Interactive Voice Response, and integration with its billing system.[17]

Q. Can you be more specific regarding Staff concerns about the CET costs?

A. Yes. In particular, Staff questions whether, as the scope of the CET project increased over time – in terms of additional functionality, or "bells and whistles," whether the Company has adequately developed a business case for the increased functionality. Just because something can be done does not mean it should be done, or that the cost impact to ratepayers is justified by the increase in functionality. The CET program is the last major project of PGE's Vision 2020 Program, introduced to the Commission in UE 215, and described as a 10-year, multi-project strategy to "implement a set of projects that collectively modernize and consolidate our technology infrastructure."[18] In UE 262, PGE reiterated that the CET program's goal continues to be to implement common systems and standardized business processes throughout the enterprise to achieve efficiency and cost effectiveness.[19] Based on the evidence that Staff was provided in this case,

[16] Staff/1106, Moore/1-5 (PGE Response to Staff DR 139 Attachment B) Confidential.
[17] Staff/1103, Moore/1-4 (PGE Response to Staff DR 489).
[18] UE 215 PGE/600, Henderson-Hosseini/22.
[19] UE 262 PGE/900, Stathis-Dillin/10-12.

PGE has not justified the significant increases in capital costs associated with the program.

Q. On what basis does Staff question the prudence of the additional costs, generally?

A. First, as discussed above, PGE has not supplied adequate information to assess the prudence of increased CET capital expenditures, generally. At the point in time that PGE seeks recovery of capital costs for the projected $128 million anticipated to become operational in 2018,[20] Staff recommends that the Company supply additional information to support its request.

Second, and most important, the increase in functionality appears to result in a far larger increase in costs to ratepayers, not less. Not only are ratepayers being asked to pay significant sums for state of the art technology systems, but they are also asked to pay for more IT staff to operate and maintain the systems, and more business and systems analysts to design and coordinate new processes to take advantage of the new efficiencies. In other words, the costs of obtaining the additional functionality and new efficiencies appear to outweigh the cost savings gained by the efficiencies. While Staff supports the Company's efforts to improve the level of service it offers its customers, the question must be asked: What is this added efficiency and convenience worth to ratepayers? Staff has not seen any evidence demonstrating that PGE has explored this question.

[20] PGE/900, Stathis-Dillin/13.

Q. What CET program costs are included in this rate case?

A. PGE's initial filing requested to recover $5.46 million in capital related to computers;[21] however, in response to a data request, the Company projects capital spending of $6.2 million.[22] The Company proposes to collect program development O&M costs, including currently unamortized deferred amounts and $3,465,000 related to projected 2018 costs, through a new mechanism.[23]

Additionally, as Staff Witness Gardner pointed out in testimony, loadings for the incremental 37.91 FTE included in the CET program development costs were omitted from the recovery mechanism proposed by PGE.[24] As Staff Witness Gardner states, Staff is proposing that the labor loadings follow the wage and salary component, which costs approximately $1.271 million.

Q. Does Staff oppose PGE's request to include capital expenditures for computers in this case?

A. No. Staff does not oppose PGE's request to include capital expenditures for computers transferred to plant in July and October 2017 in this case.

Q. Does Staff support PGE's request to include program development O&M from 2017 and 2018 in this case?

A. No. Staff recommends limiting total CET program development costs to $18.007 million, which is the cost level that was estimated and approved in

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[21] PGE/902, Stathis-Dillin/1.
[22] Exhibit Staff/1102, Moore/1 (PGE Response to Staff DR 139 Attachment A, excel file).
[23] PGE/900, Stathis-Dillin/14-15.
[24] Staff/400, Gardner at Issue 9.

UE 294,[25] until such time that PGE is able to justify the prudence of the additional costs. Limiting the recovery of program development costs to $18.007 million results in a prudence disallowance that approximates the amounts deferred in 2017 pursuant to UM 1796, as well as projected 2018 costs (inclusive of labor loadings).

Q. Please describe PGE's proposal for ratemaking treatment of program development O&M costs.

A. In the Company's most recent three general rate cases, CET O&M costs were deferred and set to be amortized over the remaining development life of the project, ending in 2018.[26] The deferral and amortization costs were included in base rates in each of the Company's general rate cases, with the exception of 2017 costs which were approved via a separate deferral.[27]

In this case, PGE proposes that the Commission issue an accounting order that would allow 2018 CET program development costs to be booked to a regulatory asset and included in rate base, along with the remaining balances from prior CET deferral vintages, and amortize these costs in base rates over ten years beginning in 2018.[28] In other words, the Company is requesting to capitalize an expense item, and to recover that amount over a ten year period at the Company's authorized rate of return. The Company

[25] UE 294 – PGE/900, Stathis-Dillin/9.
[26] PGE/900, Stathis-Dillin/14.
[27] PGE/900, Stathis-Dillin/14 (citing to Commission Order No. 16-487).
[28] PGE/900, Stathis-Dillin/15.

states that it is open to either including this amount in base rates or recovering amounts through a separate schedule.[29]

Q. Does Staff support PGE's proposed recovery mechanism?

A. Generally, yes. Staff supports PGE's proposed CET recovery mechanism as it consolidates all of the program development costs incurred over several years into a single amortization schedule that will reduce the annual impact on customer rates, with two exceptions.

First, as stated above, Staff recommends limiting total CET program development costs to $18.007 million.

Second, Staff recommends that the amortization period for recovery be limited to five years.

In addition, Staff recommends that the costs be recovered in rates through a separate schedule, which will allow recovery in rates to end as soon as costs have been fully amortized.

[29] PGE/900, Stathis-Dillin/14.

ISSUE 3: INCREMENTAL FTE-INFORMATION TECHNOLOGY/INFORMATION SECURITY

Q. Please describe PGE's request for additional IT/IS FTE.

A. PGE proposes to add 44 additional FTE for its Information Technology and Information Security departments.[30] Twenty two new FTE are proposed for each department. Of the IT positions, PGE requests seven new positions for the Office of CIO, "to provide support to T&D, infrastructure fitness, software license compliance, expanded/improved IT service delivery, and Western EIM starting in 2017." In the area of Infrastructure, PGE requests nine additional FTE "to support eastside generation facilities, provide 24/7 IT support in the Data Center, T&D, Customer Service and the Call Center." Two FTE are requested for risk management, and four new FTE for applications support. In PGE's Information Security department, 22 new FTE are requested.[31]

Many of the requested FTE for the IT department in this case have already been hired, or allocated to the 2017 budget.[32] From 2016 – 2018, PGE is increasing its IT/IS workforce 51.8 FTE, or a 9.1 percent increase. From 2014, the increase is even larger. The following table shows the growth of PGE's IT/IS workforce:

[30] PGE/500, Henderson-Hosseini-Anderson/8.
[31] PGE/500, Henderson-Hosseini-Anderson/8.
[32] Staff/1105, Moore/1-9 (PGE Response to Staff DR 481 Attachment A).

Table 1.[33]

Year	IT/IS FTE	Increment	Year-to-Year % increase
2014	234.8		
2015	234.8	0.0	0.0%
2016	272.4	37.6	16.0%
2017	309.3	36.9	13.5%
2018	324.2	14.9	4.8%

Q. How has the growth in FTE positions affected PGE's costs?

A. Yes. Growth in FTE is a major component of the growth in PGE's IT spending. Table 2 below shows the growth in the Company's IT/IS costs:

Table 2.[34]

Year	IT/IS Cost	% Increase
2014	$51,162,113	
2015	$64,637,636	26.3%
2016	$73,340,575	13.5%
2017	$75,945,530	3.6%
2018	$94,396,799	24.3%

Q. What are the reasons given by the Company for the increases in FTE?

A. PGE points to the increasing complexity and functionality of its IT systems as the main reason for needing additional personnel to maintain them.[35] From 2010 through 2016, PGE has implemented a number of new systems as part of its 10-year 2020 Vision program to upgrade and consolidate its IT infrastructure. In 2009 the Company had 404 software applications that it needed to administer. By 2018 that number will be reduced to 241

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33 PGE/400, Workpapers: 2014-2018_FTE_WS_By OperationRC Class_01-30-17.
34 PGE/501, Henderson-Housseini-Anderson/1.
35 PGE/500, Henderson-Housseini-Anderson/8.

applications.[36] However, PGE states that the reduction in the number of applications does not translate to a reduction in personnel needed to operate and maintain the systems.[37] Not only has the number of PGE personnel needed to maintain the systems increased, but the hardware and software maintenance agreements with vendors has increased as well, by approximately $4.9 million from 2016 to 2018.[38]

In the realm of Information Security, the Company states that "while PGE had spent significant effort and expense in increasing its security capabilities in recent years…" PGE is "concerned with the increase in scope and severity of recent cyber-attacks on America's critical electronic networks and it is necessary that we take steps now to maintain the security, reliability, and safety of our systems."[39]

Q. How did Staff review PGE's proposed FTE increase?

A. Staff issued 45 data requests regarding the Company's increase in FTE throughout its organization in an attempt to understand the reason for such a significant increase, including a series of multi-part questions targeted to the specific IT positions.[40] We also asked for studies, management reports, benchmarking studies, variance analyses, and analyses quantifying gained efficiencies that would justify the increase in positions.[41] Staff also held a

[36] PGE/500, Henderson-Housseini-Anderson/6.
[37] PGE/500, Henderson-Housseini-Anderson/6.
[38] PGE/500, Henderson-Hosseini-Anderson/12.
[39] PGE/500, Henderson-Hos4eini-Anderson/16.
[40] Staff/1105, Moore/10-37 (PGE Responses to Staff DR's 504-523).
[41] Staff/1105, Moore/38-46 (PGE Response to Staff DR 558).

workshop on May 5, 2017, with all the parties in the docket in which the increase in FTE was extensively discussed.

Q. What does Staff conclude from its review?

A. First, Staff's review relies on the information that the Company provided through 45 targeted data requests, and its opening testimony. In reviewing this information, Staff could not identify a comprehensive internal process, studies, or benchmarking for evaluating the efficiency and effectiveness of its labor resource in determining what PGE's actual needs are. In essence, the testimony and voluminous responses to data requests, as well as the discussion in the May 5, 2017, workshop basically amount to PGE simply asserting that it needs more people – and it needs all of those people now.

Since 2010, PGE has filed five requests for rate increases (UE 215, February, 2010; UE 262, February, 2013; UE 282, February, 2014; UE 294, February 2015; UE 319, February 2017) in which it has asked ratepayers to pay for hundreds of millions of dollars in technology upgrades. PGE asserted that these IT initiatives would increase productivity and efficiencies. In UE 262, PGE testimony claimed that its Vision 2020 program would improve the company's effectiveness, capabilities and efficiencies, and eliminate complexity.[42] "Through the 15 initiatives, IT will be able to continue supporting PGE's growing need for technical infrastructure and services while maintaining a relatively flat IT employee count. From 2011 through 2014, we project a net reduction of 7.8 IT

[42] UE 262 PGE/600, Henderson-Hosseini/23-24.

FTEs."[43] But as we see, this has not been the case. In addition to maintenance costs paid to hardware and software vendors increasing, PGE now claims that more – not less – people are required internally to administer these new systems.

Q. Will the increase in FTE result in a decrease in the use of contract labor within the IT organization?

A. No. PGE states that current employees are working beyond their planned capacity, and the work has increased beyond their existing scope, and no cost savings will result from the additional FTEs requested in this case.[44]

Q. Will the increase in FTE in the IT/IS division result in offsetting decreases elsewhere in the PGE organization, as a result of general efficiencies gained from the new systems?

A. No. The Company is requesting significant FTE increase in all areas of the organization. In Transmission and Distribution, which I discuss below, the Company seeks to add 167 new FTE. Other FTE increases are discussed in other Staff testimony.

Q. What is Staff's response to the 22 additional FTE that PGE is requesting for its Information/Cyber-Security department?

A. As with the FTEs requested for the IT department, PGE's analysis and documentation of the need for the additional FTE for the IS department is generally limited to high-level descriptions. Several positions are specifically requested to staff on a 24/7 basis the new Information Security

[43] UE 262 PGE/600, Henderson-Hosseini/25.
[44] Staff/1105, Moore/10-14 (PGE Response to Staff DRs 504, 505, 506).

Operations Center (ISOC). PGE has also requested a significant number of FTEs that are required to assure adequate protection for PGE's systems from cyber attacks. Staff supports PGE's efforts to develop systems, processes and obtain the necessary information security expertise to protect the power grid and be able to provide safe and reliable service.

However, as is the case with the requested IT positions, despite asking for the information, Staff has not seen any studies, memoranda, analysis, benchmarking, or any comprehensive analysis done by the Company to evaluate its IS program in terms of identifying the need for additional resources and whether PGE is prudently managing its costs. The Commission is simply being asked to take PGE's word for it: the threat of cyber attacks is real and it needs more people to protect its systems. Staff continues to question whether PGE actually *needs* 22 additional FTEs, or does the Company need people with different skill sets than what they currently have, or could PGE deploy existing resources differently? PGE has not made its case.

In addition, Staff wonders whether PGE is being overly optimistic in its expectation that it will be able to hire 22 people with the relevant cyber-security expertise within the next year. The shortage of workers with cyber-security skills is well-documented.[45] As of April 14, 2017, PGE had not hired

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[45] See "Through the Eyes of Cyber Security Professionals: Annual Research Report," Dec 2016, accessed at: https://c.ymcdn.com/sites/www.issa.org/resource/resmgr/cscl/ESG-ISSA-Research-Report_Sta.pdf
See also: http://www.networkworld.com/article/3177374/security/cybersecurity-skills-shortage-holding-steady.html

any of the requested 22 Information Security FTE.[46] PGE's response to DR 481 indicates that it hopes to hire an IS T&D support services manager in May of 2017. One ISOC manager and two ISOC analysts are estimated to be hired in July and August of 2017. The remainder of FTEs is estimated to be hired in either December of 2017 through April 2018.[47]

Q. What is PGE's "Information Security Roadmap"?

A. PGE's testimony describes the Information Security Roadmap as a series of ten initiatives comprising approximately 40 projects over 5 years designed to address the potential impact of security risks it has identified.[48] The ten key initiatives are briefly described in PGE/500 beginning on pg 18, and include the ISOC, Identity and Access Management (IAM), Risk Based Governance, Incident Response, Business Impact Analysis, Vendor third-party management, Architecture, Vulnerability Management, Security Awareness and Training, and Data Protection.

Q. Does PGE provide more detailed information about the Information Security Roadmap than the brief descriptions offered in its testimony?

A. Yes, with its testimony PGE filed confidential workpapers that includes a presentation dated November 2, 2016, providing a high-level summary of what appears to be initial planning and budgeting for the series of initiatives described above. Staff notices that the preliminary budget estimates of

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https://www.virusbulletin.com/virusbulletin/2016/12/vb2016-paper-mind-gap-criminal-hacking-and-global-cybersecurity-skills-shortage-critical-analysis/
[46] Staff/1105, Moore/1-9, (PGE Response to Staff DR 481 Attachment A).
[47] Staff/1105, Moore/1-9, (PGE Response to Staff DR 481 Attachment A).
[48] PGE/500, Henderson-Hosseini-Anderson/18-20.

dedicated IT/IS personnel needed to implement this series of initiatives equates to approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. It should be emphasized here that this presentation is the only internal analysis regarding PGE's incremental FTE request that Staff has seen, and the budget estimates for this major series of ten key initiatives comprising approximately 40 projects over the next 5 years is substantially less than what PGE is requesting in this case.

Q. Does Staff recommend an adjustment to the number of FTE for IT/IS departments?

A. Yes. Based on the discussion above, Staff recommends an adjustment that removes 11 of the 22 incremental FTE from the IT department, and removes 12 of the 22 incremental FTE from the IS department. Staff is not convinced, from reviewing PGE's budget and planning documents, that the Company needs or plans to in fact have all of its stated FTE in 2018. Further, Staff's numbers assume all are hired and available on January 1, 2018 versus the likely sequence of filling positions over time. Finally, some of these positions may be filled internally by re-allocating resources within the Company.

ISSUE 4: INCREMENTAL FTE-TRANSMISSION AND DISTRIBUTION

Q. Please summarize PGE's request with regard to additional FTE in the Transmission and Distribution organization.

A. In total, PGE plans to hire 169 additional FTE's in its Transmission and Distribution departments between 2016 and 2018, in addition to retaining its contract labor.[49] The Company states that 90 additional FTEs are needed to support its strategic capital improvements that were identified in a risk-management review. These FTE include transmission and engineering designers, service and design project managers, substation operations and engineering, and support staff such as contract management and fleet and garage operations.[50] PGE states that approximately 57 FTEs are needed to support the increase in customer-driven capital projects, seven FTEs are needed to support PGE's compliance with NERC and NESC standards. Seven FTEs are required to "help improve processes and create efficiencies in support of the distribution business," six FTEs are required for PGE's participation in the Western EIM, and three FTE's are needed for engineering PGE's Smart Grid initiatives.[51]

Q. What reasons does PGE give for this increase in FTE?

A. PGE gives several reasons: its workload is increasing, in both the increase in new customer connections and strategic capital improvements, including substation upgrades, underground replacement program and PCB

[49] PGE/800, Nicholson-Bekkedahl/17.
[50] PGE/800, Nicholson-Bekkedahl/17.
[51] PGE/800, Nicholson-Bekkedahl/18-19.

ISSUE 4: INCREMENTAL FTE-TRANSMISSION AND DISTRIBUTION

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A. In total, PGE plans to hire 169 additional FTE's in its Transmission and Distribution departments between 2016 and 2018, in addition to retaining its contract labor.[49] The Company states that 90 additional FTEs are needed to support its strategic capital improvements that were identified in a risk-management review. These FTE include transmission and engineering designers, service and design project managers, substation operations and engineering, and support staff such as contract management and fleet and garage operations.[50] PGE states that approximately 57 FTEs are needed to support the increase in customer-driven capital projects, seven FTEs are needed to support PGE's compliance with NERC and NESC standards. Seven FTEs are required to "help improve processes and create efficiencies in support of the distribution business," six FTEs are required for PGE's participation in the Western EIM, and three FTE's are needed for engineering PGE's Smart Grid initiatives.[51]

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[49] PGE/800, Nicholson-Bekkedahl/17.
[50] PGE/800, Nicholson-Bekkedahl/17.
[51] PGE/800, Nicholson-Bekkedahl/18-19.

transformer testing and replacement. The increase in workload has driven increases in overtime spending. The Company notes that it incurred $12.4 million in overtime costs in 2016, an increase of 5 percent over 2015. Additionally, PGE is expecting a large number of experienced employees to retire over the next three years. By hiring proactively, PGE is able to assure that the knowledge and experience of the retiring workers gets transferred to the next generation of employees.

Q. Does Staff have concerns about the number of FTE requested for the Transmission and Distribution organization?

A. Yes, and they are similar to the concerns expressed above for the FTE increase in IT/IS organization, in that Staff has not seen evidence that PGE conducts any sort of comprehensive analysis, or performed any benchmarking for evaluating the efficiency and effectiveness of its labor resource in order to determine what its actual needs are or what performance standard represents best practices. In a data request, Staff asked PGE whether it had requested that managers identify the need for new positions in 2017 or 2018. PGE provided two memoranda that were sent out to department managers identifying their budget needs for 2017 and 2018.[52] For the 2017 budget, the memo dated August 18, 2016, emphasized that "requests for additional employees are not permitted unless approved by your officer."[53] A second memo dated September 14, 2016, pertained to "2018 Rate Case budget submittals" in which the

[52] Staff/1104, Moore/1-4 , (PGE Response to Staff DR 623 Attachments A and B).
[53] Staff/1104, Moore/2 (PGE Response to Staff DR 623 Attachment A).

managers were asked to identify their labor and non-labor costs/needs for 2018. Whereas the 2017 memo very clearly emphasized that department heads were not to exceed their budget targets for 2017, there was no such emphasis in the call for the 2018 general rate case budget submittal.[54] Managers were even encouraged to show incremental initiatives from their recently submitted 2017 budget: "Your 2018 budget ***should*** reflect incremental initiatives from your recently submitted 2017 budget. If you have new programs, please fill out an O&M Adjustment Request," and "If you need to add or remove positions incremental to your 2017 budget, please contact your Planning Analyst and fill out a New Position Request."[55] The change in wording for the requests is subtle, but the dramatic shift in emphasis is clearly there. It appears that department managers were being encouraged to include incremental projects and spending in their 2018 budget whereas in 2017, department managers were admonished to stay within their budget targets. Only companies with monopoly power can afford to encourage new initiatives to drive additional spending with costs being a secondary consideration.

Q. Please discuss the reasons PGE gives for this increase in FTE?

A. PGE asserts that it needs the 57 employees for the "customer-driven" work to address (1) an increasing workload due to an increasing amount of customer connects and continuous improvement projects; (2) increases in

[54] Staff/1104, Moore/3-4 (PGE Response to Staff DR 623 Attachment B).
[55] Staff/1104, Moore/4 (emphasis added) (PGE Response to Staff DR No. 623 Attachment B).

overtime; and (3) a maturing workforce.[56] PGE says its customer-driven workload is increasing due to an increase in new customer connections and that the increase in workload has driven increases in overtime spending. The Company notes that it incurred $12.4 million in overtime costs in 2016, and increase of 5 percent over 2015.[57] Additionally, PGE is expecting a large number of experienced employees to retire over the next three years.[58] PGE opines that hiring proactively will ensure that the knowledge and experience of the retiring workers gets transferred to the next generation of employees.[59]

PGE states that it needs 90 new T&D FTEs for capital improvements to its grid. PGE states the needed improvements were identified in connection with a new risk-management strategy adopted subsequent to its hiring of a third-party assessor in 2012 to review its T&D asset management strategy.[60] After receiving the third-party assessment, PGE created a "Strategic Asset Management" (SAM) department with the T&D organization, which developed a risk assessment methodology.[61] Using this methodology, SAM assessed the majority of PGE's T&D asset base between 2013 and 2015 and released its first draft of the "T&D Risk Register in 2016."[62]

[56] PGE/800, Nicholson-Beddedahl/17.
[57] PGE/800, Nicholson-Beddedahl/17.
[58] PGE/800, Nicholson/Bekkedahl/17.
[59] PGE/800, Nicholson/Bekkedahl/17.
[60] PGE/800, Nicholson/Bekkedahl/9.
[61] PGE/800, Nicholson/Bekkedahl/9-10.
[62] PGE/800, Nicholson/Bekkedahl/11.

Q. Does Staff have concerns regarding the need for these 147 new FTEs?

A. Yes. First, with respect to new customer connections, PGE's testimony reflects that it anticipates that growth in new customer connections, has begun to level off, and has still not approached the level of new customer connections that PGE experienced in 2006, which had over 14,000 new connections. In contrast, PGE is forecasting 13,300 new connections in 2018. A staff data request response, in which PGE is asked whether the decline in new customer connections in 2007 through 2011 corresponded with a decline in the T&D workforce, is pending.

PGE's assertion that hiring FTEs is necessary to reduce overtime for new customer connections is not compelling. During the recession, new connections fell 66% from 2007 to 2011.[63] Between 2011 and 2016, new customer connections increased at an annual rate of 20%. PGE forecasts a leveling off in 2017 and 2018, with continued growth of 12 percent between 2016 and 2018. It is not clear why PGE now needs 57 new FTEs to address new customer connections.

It is also not apparent why PGE needs to hire 90 FTEs for strategic capital improvements by the end of 2018. As discussed above, PGE's process for assessing the need for the improvements began in 2012. The assessment itself took three years. In light of the pace of PGE's efforts to date, Staff disagrees that PGE has shown that ratepayers should pay for 90 incremental FTEs so that PGE may finish the strategic improvements by the end of 2018.

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[63] PGE/800, Nicholson/Bekkedahl/5.

Q. Does Staff have a recommendation regarding FTE increases for Transmission and Distribution?

A. Yes. Based on the discussion above, I recommend an adjustment that removes costs of 40 of the 90 FTEs that PGE plans to hire for capital improvements and 27 of the 57 employees that PGE plans for customer-driven work. I also recommend that costs for contract labor for T&D O&M be reduced by a corresponding ratio of 67/169, which is 40 percent.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 319
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1101

Witness Qualifications Statement

June 16, 2017

WITNESS QUALIFICATIONS STATEMENT

NAME:	Mitchell Moore
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem Oregon 97301-3612
EDUCATION:	Bachelor of Arts, Journalism and Political Science University of Hawaii at Manoa (1992)
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon since 2009, with my current position being a Senior Utility Analyst in the utility program's Energy Rates, Finance and Audit division. My prior position at the Commission was as a Senior Telecommunications Analyst, where my assignments included reviewing carrier interconnection agreements, wholesale service quality, and resolution of carrier-to-carrier complaints. Prior to my utility regulatory career, I worked with AT&T as a loop electronics coordinator, designing and implementing high-speed broadband and fiber optic services in Los Angeles. I have also worked as an outside plant design engineer with Qwest Corporation, and I spent several years as a newspaper reporter with the Honolulu Star-Bulletin.

CASE: UE 319
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1102

Exhibits in Support
Of Opening Testimony

June 16, 2017

May 17, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE *First Supplemental* Response to OPUC Data Request No. 139
Dated March 6, 2017

Request:

Please provide a list of *each* project or program that is anticipated to transfer to plant in 2017.

For each individual project, please also provide the following:

a. **General description of project;**
b. **Actual or anticipated date of transfer to plant;**
c. **Page(s) of PGE UE 319 testimony that relates to the project; and**
d. **All documentation that PGE relied upon to approve the project, including any risk/benefit analysis and consideration of alternatives to such project.**

Initial Response (dated March 24, 2017):

PGE objects to this request based on the grounds that it is unduly burdensome. Without waiving its objection, PGE responds as follows:

Attachment 139-A provides a listing of 2017 projects and the month they are expected to close.

Attachment 139-B contains Project Justifications (maintained in PowerPlan) for projects that have amounts closing to plant in 2017. If OPUC Staff, or other Parties, would like to review further documentation on specifically selected projects, please contact PGE and we will set up a time to review at PGE Offices.

Attachment136-B contains protected information and is subject to Protective Order No. 17-057.

First Supplemental Response (dated May 17, 2017):

Attachment 139-C provides Project Justifications for nine projects that were inadvertently not included in PGE's original response. Those projects are as follows:

- P23599
- P35938
- P36029
- P36146
- P36229
- P36272
- P36280
- P36284
- P36294

UE 319

Attachment 139-C

Protected and Subject to Protective Order No. 17-057

Provided in Electronic Format only

Documentation for 2017 Projects Not Included in Original Response

CASE: UE 319
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1103

Exhibits in Support
Of Opening Testimony

June 16, 2017

Exhibit 1103 is confidential and

Is subject to Protective Order No.17-057

CASE: UE 319
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1104

Exhibits in Support
Of Opening Testimony

June 16, 2017

June 2, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 623
Dated May 18, 2017

Request:

In 2016 or 2017 did PGE request that PGE managers or employees identify the need for new positions at PGE in 2017 or 2018? If yes, please provide such communications. If no, how did PGE develop the data contained in PGE/702?

Response:

Yes. PGE issues an annual "O&M budget call" memo requesting that managers submit their proposed labor and non-labor budgets for the upcoming calendar year. Attachments 623-A and 623-B provide the 2017 and 2018 O&M budget call memos.

UE 319

Attachment 623-A

Provided in Electronic Format only

2017 and 2018 O&M budget call memo

UE 319

Attachment 623-B

Provided in Electronic Format only

2018 Rate Case budget submittal memo

Aug. 18, 2016

To: All management and budget coordinators
From: Dee Outama, director, Corporate Planning

2017 and 2018 O&M budget call

It's time to start preparing your 2017 and 2018 department budgets. The budget process will be completed in two phases:

1. The **2017 budget** entry will be open for **one week** starting **Thursday, Aug. 25,** and need to be submitted through workflow in PowerPlant to your Corporate Planning analyst on or before **Wednesday, Aug. 31**.
2. The **2018 budget** process will begin with a budget call on **Friday, Sept. 23**, with adjustment forms due on **Wednesday, Sept. 28.** Specific guidance for 2018 will be provided at a later date.

Direction for 2017 budgets:

- **2017 budget target:** The O&M Budget template will be populated with your 2017 budget target. It is critical that you not exceed your department target.
- **What is prepopulated in PowerPlan:** The O&M budget template will be updated with the 2017 target budget data and current department labor resources. It will also include O&M budget module with costs that are associated with 2017 Capital Review Group recommended projects.
- **Query your budget:** Click the link "2017 Budget Entry" on your PowerPlan dashboard. Data will be available on Monday August 22nd.
- **Budget submission:** Select **Budget Version "2017 Budget v1"** on the budget entry screen to update and submit your budget for approval.
- **Changes to the O&M budget:**
    - ***If increases are offset with other department reductions include them in your 2017 budget.*** This will keep your department budget consistent with the 2017 targets.
    - ***If increases are not offset, do not include in your 2017 budget***. Submit an O&M Budget Adjustment Form to your Planning Analyst. The forms will be reviewed within each

Key dates

Aug. 25 — 2017 budget process begins

Aug. 31 — Completed 2017 budget due in PowerPlan

Sept. 23 — 2018 budget process begins

Resources

2017 Budget Instruction Manual

Quick-Reference Guides

PowerPlant O&M Budgeting Training

Accessing and entering budget adjustments are located on the Corporate Planning page on myPGE

New Position Form

officer's functional area.

- ***Requests for additional employees are not permitted unless approved by your officer***. Position requests must include a specific justification and have a clear business benefit. Contact your Planning Analyst for guidance on how to document these requests using the New Position Form on the Corporate Planning website.

- **O&M from capital projects:** One-time O&M from capital projects is included in your targeted budget.

Help is available: Your Corporate Planning analyst is available to answer questions and provide assistance throughout this process. Corporate Planning will hold office hours for individuals who need support preparing their budget:

Corporate Planning Budget Support

3WTC Level 1 Training Room

Date	Day	Times
8/25/2016	Thursday	8 a.m. – 4 p.m.
8/26/2016	Friday	8 a.m. – 12 p.m.
8/29/2016	Monday	1 p.m. – 4 p.m.
8/30/2016	Tuesday	1 p.m. – 4 p.m.
8/31/2016	Wednesday	1 p.m. – 4 p.m.

Thank you in advance for the work you will put into developing the 2017 and 2018 budgets in the coming weeks.

Sincerely,

Dee Outama

Sept 14, 2016

To: All management and budget coordinators
From: Dee Outama, Director, Corporate Planning

2018 Rate Case budget submittals due September 23rd

Thank you all for your hard work and timely submittals of your 2017 operating budgets. Our 2017 budget will serve as the foundation for our 2018 General Rate Case. Like prior years, we ask managers only to identify major budget and staffing changes as well as efficiency savings from 2017 to 2018. Your Planning Analyst will do the rest.

Below are some general guidelines regarding how this process will work. Your Planning Analyst is available to answer any additional questions or concerns, and are prepared to work closely with departments that have special considerations that need to be addressed during this budget cycle.

The 2018 GRC will follow the following guidance:

- **Overview** – Our 2017 budget will serve as the foundation for our 2018 General Rate Case budget.
    - **To view your final incurred 2017 budget**: run the query called "2017 O&M Entry" which is located on your PowerPlan dashboard.
    - **Labor and Non-Labor Escalations for all departments:** Please note that budget escalation will be system generated for all departments. There is no need to submit O&M Adjustment Request forms for escalations.

- **Incremental Decreases/Increases** – If you have a change in O&M dollars or FTE's to your 2018 budget, you need to complete an **O&M Adjustment Request** and/or a **New Position Request**. Forms must be submitted to Corporate Planning by **Friday, September 23rd.** All proposed increases will be evaluated by the Officer team, with approved changes added to the 2018 budget by Corporate Planning.

- **No Changes** – If you have no changes to your 2018 department budget, you do not need to do anything. Your Planning Analyst will submit your 2018 budget for you.

As you think about your 2018 budget please consider the following:

- **Cost savings and efficiencies:** As in past rate cases, there will be an emphasis on capturing measurable cost savings resulting from efficiency initiatives such as T&D Transformation, IT Vision, Customer Engagement Transformation and other ongoing efforts. Please work with your Planning Analyst to submit identified decreases in your 2018 budget relative to your 2017 budget even if they are offset by other increases (which should be documented in the O&M Adjustment Request)

- **New programs:** Your 2018 budget should reflect incremental initiatives from your recently submitted 2017 budget. If you have new programs please fill out an O&M Adjustment Request.

- **New positions:** If you need to add or remove positions incremental to your 2017 budget please contact your Planning Analyst and fill out a New Position Request.

Thank you in advance for your support in developing the 2018 GRC budget. If you have any questions or need any assistance with the process please contact your **Planning Analyst.**

Sincerely

Dee

CASE: UE 319
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1105

Exhibits in Support
Of Opening Testimony

June 16, 2017

April 28, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 481
Dated April 14, 2017

Request:

With regard to the increase in 44 FTE positions requested for the IT/IS department:

a. **For each FTE, please indicate whether the procurement process has started for that FTE and if it has, the status of the process. If the procurement process has not started, please provide best estimate of when will start. For all 44 FTE's, provide best estimate on when FTE will be hired.**

b. **For each of the years beginning in 2010 through 2016, please provide the number of IT/IS FTE positions allocated to the department and the number of FTEs employed in the department. For each year in which there were unfilled allocated positions, please specify how many vacancies and the duration.**

Response:

a) Attachment 481-A provides the current status of each of the 44 FTEs requested for the IT/IS organization.

b) PGE's financial systems do not allow for the tracking of individual vacancies and their duration. However, a representation of vacancies can be calculated by comparing the actual number of FTEs and the budgeted number of FTEs for each year.

PGE Attachment 481-B provides:

- The IT/IS actual number of FTEs by department from 2012 to 2016;
- The IT/IS budgeted number of FTEs from 2013 to 2016; and
- The variance between IT/IS actual FTEs and budget FTEs.

It is difficult for PGE to provide accurate data from before 2012 because PGE converted to a new financial system in 2011. In addition, the FTE detail provided in PGE's general rate cases (GRCs) is assembled and formatted for the specific FTE exhibit (see PGE Exhibit 401) and is consistent with similar FTE exhibits in previous GRCs. In short, the FTE exhibit is assembled only for regulatory rather than managerial purposes and absent these GRC exhibits, PGE does not have comparable FTE budget detail. Consequently, PGE is not able to include an FTE budget for 2012 in a manner comparable to the 2012 actuals (i.e., PGE did not have a 2012 or 2013 GRC with which to develop the 2012 FTE budget for regulatory purposes).

UE 319

Attachment 481-A

Provided in Electronic Format only

IT/IS FTEs Hiring Status

UE 319

Attachment 481-B

Provided in Electronic Format only

IT/IS FTEs - Actual, Budget, and Variance 2012-2016

Title	FTE	Hiring Process	
IT - GENERAL			
Office of Chief Information Officer (OCIO)		**Status of the Hiring Process / Estimated Start Date of the Hiring Process**	**Estimate Date of the FTE Hiring**
IT Business Relationship Management Analyst – T&D	1	10/2017	1/2018
IT Business Relationship Management Analyst, Customer Service and Delivery	1	10/2017	1/2018
Business Analyst	1	11/2017	1/2018
Software Asset Manager	1	4/2017	6/2017
Service Level Manager	1	9/2017	1/2018

Analyst, Business and Design, EIM	2	Completed Completed	Completed Completed
Infrastructure			
Specialist IV, Technical	1	Started	As soon as Found
System Analyst III, 24/7 Operations in Data Center	4	10/2017	1/2018
System Analyst III, Citrix Support	1	Started	As soon as found
System Analyst IV, TCC IVT Support	1	10/2017	1/2018
Specialist	1	10/2017	1/2018
Design Build Specialist	1	10/2017	1/2018
Applications			

IT Systems Manager	1	Completed	Completed
Quality Assurance Analyst	2	9/2017	1/2018
Quality Assurance, Release Manager	1	9/2017	1/2018
Risk			
Governance Risk Compliance System Support	1	10/2017	1/2018
Compliance Manager	1	4/2017	7/2017
TOTAL IT FTEs	**22**		

INFORMATION SECURITY PROGRAM HIRING PROCESS			
Security Assurance		**Status of the Hiring Process / Estimated Start Date of the Hiring Process**	**Estimated date of the FTE Hiring**
ANALYST IV,SR Information Security	2	10/2017	1/2018
Analyst IV, Security Assurance	1	1/2018	4/2018
Analyst IV, Threat Analyst	1	1/2018	4/2018
Information Security Operations Center (ISOC)			
Manager, ISOC	1	4/2017	7/2017
Analyst, ISOC	2 3	5/2017 10/2017	8/2017 1/2018
Spec V, Security Monitoring	1	10/2017	1/2018
Specialist, ISOC, T&D	2	10/2017	4/2018

Identity Access Management (IAM)			
Analyst IV, Applications Developer	2	9/2017	12/2017
Analyst IV, Role Manager, RBAC	1	10/2017	1/2018
Analyst IV, Governance, Access & Reporting	1	9/2017	12/2017
Analyst III, Identity/Access Bus Analyst	1	9/2017	12/2017
Information Security Roadmap			
Program Manager, ISP	1	6/2017	9/2017
Analyst IV, Program Bus Analyst	1	10/2017	1/2018
T&D/Security			
Manager, T&D OT Support Services	1	3/2017	5/2017
Admin, T&D Substation Support	1	12/2017	2/2018
Total ISP FTEs	**22**		
Total IT FTEs	**44**		

May 3, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 504
Dated April 21, 2017

Request:

Regarding PGE 502, pg 1 – IT Business Relationship Management Analyst – T&D FTE:

a. **What effect will the "reallocation of work to new Business Relationship Management Analyst: have on workload of employees currently performing the work?**

b. **Will any of the FTEs currently performing the work that will be done by Business Relationship Management Analyst be reassigned to different department? If so, please identify and describe the reassignment and tasks to be performed by the FTE.**

c. **Does the creation of a new position and reallocation of work previously "allocated among multiple resources" result in cost savings in departments currently expending resources to perform tasks? If yes, pleaes identify how this cost reduction is addressed in revenue requirement. Please explain both answers.**

Response:

a. Employees currently performing these duties are temporarily working beyond their planned capacity. As a result, these employees are often constrained in their ability to complete all required deliverables without significant negotiation and/or re-prioritization. By recognizing that the work has increased beyond what the existing resources can accomplish, and by adding resources as required, we are better able to focus on primary role responsibilities.

b. The work that is currently performed in the Business Relationship Management group will continue to be performed in that group. These employees will simply be able to better focus on their current job duties and deliverables.

c. No cost savings will result from the additional FTEs.

May 4, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 505
Dated April 27, 2017

Request:

Regarding PGE 502, pg 1 – IT Business Relationship Management Analyst – Customer Service & Delivery:

a. **Is work to be performed by Business Relationship Management Analyst, Customer Service and Delivery currently being performed by employees? If yes, please identify employees and how much of their time is spent on tasks that will be performed by new FTE?**
b. **Does the creation of a new position result in cost savings in departments currently expending resources that will be performed by new FTE> If yes, please identify how this cost reduction is addressed in revenue requirement. If not, explain why not.**
c. **Who will be the direct supervisor of the IT Business Relationship Management Analyst – Customer Service and Delivery?**

Response:

a. The work planned for the Business Relationship Management Analyst (BRM Analyst) is currently being performed by the Business Relationship Manager – Customer Service and Delivery (Customer Service BRM) and other employees as they are available to assist. However, these employees are over capacity and are often unable to complete their required work. This role has been partially mitigated in 2016 and 2017 by the ability to transfer some of the work to the Customer Touchpoints project. But, this work will return to this work group in 2018 as the Customer Touchpoints project launches.

b. No cost savings in departments will result from adding this new FTE. As noted above in part (a), the work is currently being performed by the Customer Service BRM (this role will remain).

c. The direct supervisor for the BRM Analyst will be the Customer Service BRM.

May 4, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 506
Dated April 21, 2017

Request:

Regarding PGE 502, pg 1 – Business Analyst:

a. **Does PGE plan to terminate the contract for services that will be performed by the new Business Analyst? If yes, when will this occur? If no, please explain why not.**

b. **What does PGE project will be the cost savings associated with the hiring of an FTE rather than using contract labor for these services? Are these cost savings reflected in test year revenue requirement?**

Response:

a. PGE does not plan to terminate the contract for services performed by the Business Analyst. PGE plans to supplement the current contractor Business Analyst with the requested FTE. The scope for Cyber Security projects has identified a requirement for more analyses and requirements gathering than one FTE would be able to accommodate. Currently there are three large cyber security projects in flight: Data Access Management; Password Application Management; and Identity Access Management. They all have specific milestone dates, and require additional resources. After the projects are completed we would release the contractors working on the major projects and the FTE would move to an operational support role.

b. PGE does not expect significant cost savings to result from hiring this additional FTE. However, this additional FTE is required to provide analyses and complete requirements to ensure increased cyber security for PGE's customers, employee data, and assets.

May 4, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 507
Dated May 4, 2017

Request:

Regarding PGE 502, pg 1 – Software Asset Manager:

PGE asserts that the spreading the role of software license compliance over all IT operating functions "increases license compliance costs." Will the new FTE result in cost reductions in other areas? If yes, how are all anticipated cost reductions associated with the new FTE and concentration of role of software compliance reflected in PGE's revenue requirement?

Response:

As the standard software licensing model has changed and developed over the past few years, and with the significant increase in software compliance audits by major software providers, PGE has identified a need to centralize the software asset management process within the company's Information Technology (IT) department to prevent the company from incurring significant costs as a result of being non-compliant. This position's responsibilities include: (1) ensuring that PGE effectively manages software spending at the enterprise level; (2) improving PGE's ability to meet compliance and licensing requirements and standards. The implementation of this role is primarily focused on avoidance of costs and penalties resulting from non-compliance with software agreements.

May 4, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 508
Dated April 27, 2017

Request:

Regarding PGE 502, pg 1 – Service Level Manager:

a. **Please explain what is meant by "managing IT service levels." Is this task currently performed by PGE employees? Please explain.**

b. **How much of the new FTE's time will be spent "identify(ing), measure(ing) and improve(ing) service delivery"?**

c. **Are the tasks of identifying, measuring and improving service delivery currently being peformed by PGE employees? Please explain.**

Response:

a. The Service Level Manager is identified in PGE's IT Infrastructure Library (ITIL) framework as a key IT function.[1] The Service Level Manager negotiates Service Level Agreements with each of PGE's business clients, clarifying the responsibilities and requirements of both parties. In addition, the manager designs and suggests improvements to IT services in accordance with the agreed service level targets. The Service Level Manager also reports on IT service levels and IT service performance.

b. Service Level Manager will initially focus on developing metrics to identify and measure service levels consistently. As the role and the associated processes mature in 18 to 24 months, the Service Level Manager will work towards continual service improvement. We expect that the Service Level Manager will be dedicated to identification (20%), measurement (40%), and service improvement (40%).

[1] The ITIL provides a standard and best-practice services framework for PGE's IT organization

c. Service Level Management duties are currently distributed across the IT organization, and are at a low maturity level due to the limited coverage for the key duties performed by this role.

May 3, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 509
Dated April 21, 2017

Request:

Regarding PGE 502, pg 2 – Specialist IV, Technical:

a. **Does PGE anticipate reduced overtime or other benefits associated with full-time technical support for generation sites on the eastside? Please explain.**

b. **Are any cost savings identified in response to a. reflected in test year revenue requirement?**

Response:

a. No reduction in overtime is expected. This role will provide an increase in IT support for east side generation facilities, including shorter response time, faster issue resolution time, and more focused support for these critical generation facilities. This support is currently provided from downtown Portland, resulting in long transit times to resolve issues.

b. There are no cost savings expected.

May 4, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 510
Dated April 21, 2017

Request:

Regarding PGE 502, pg 2 – Systems Analyst III, 24/7 Operations in Data Center:

a. **Does PGE currently provide 24/7 support of its data center?**

b. **If the answer to a. is "yes," how is PGE currently meeting the need for services that it anticipates will be met by four new FTE's?**

c. **What off-setting cost savings does PGE anticipate from procurement of four new FTE's, i.e., less overtime, less contract labor?**

d. **How is this cost savings identified in c. reflected in the test year revenue requirement?**

Response:

a. No, PGE does not currently provide 24/7 onsite support in the data center. Current support after hours is limited to on-call support.

b. Not Applicable - PGE does not currently provide 24/7 support in the data center.

c. PGE does not anticipate any off-setting cost savings to result from the addition of 24/7 support in the data center. The primary benefit for the Systems Analyst roles will be increased support, monitoring, and triage for systems that increasingly require 24/7 support as well as for new systems that require rapid issue response.

d. Not Applicable – PGE does not anticipate any off-setting cost savings to result from the addition of 24/7 support in the data center.

May 4, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 511
Dated April 21, 2017

Request:

Regarding PGE 502, pg 2 – Systems Analyst III, Citrix Support:

a. **Regarding the statement that "(i)nfrastructure team is currently limited in number of FTE to provide adequate Citrix support to business," please explain what steps PGE is currently taking to address inadequate support?**

b. **How has inadequate Citrix support affected PGE's service or operations?**

c. **Does PGE anticipate any offsetting cost savings from hiring new FTE, i.e., reduced overtime? If yes, how is the cost savings reflected in the test year?**

Response:

a. To provide the best possible support with available resources, the Information Technology (IT) organization has worked to expand the capabilities of support teams so that the IT Enterprise Operations Center and IT Service Desk can address basic Citrix issues. Also, IT has expanded and/or refined monitoring and alerting for Citrix systems, thereby providing improvements in response and resolution time. These are interim measures that often fall short of the support required for Citrix systems.

b. The lack of adequate Citrix support negatively impacts the availability and uptime of critical PGE applications (e.g., PGE's outage management system). The lack of Citrix support resources increases response and resolution time. Citrix is increasingly a key component of the IT infrastructure, and Citrix downtime is often highly impactful and costly to the users of the system.

c. PGE does not expect any direct cost savings to result from the addition of the System Analyst III, Citrix Support positions. There are potential avoided costs that result from increasing IT's capability to perform planned maintenance and provide sufficient support coverage. This additional support will reduce the potential for downtime and increase the response and resolution time for systems that utilize Citrix.

May 4, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 512
Dated April 21, 2017

Request:

Regarding PGE 502, pg 2 – Systems Analyst IV, TCC IVT Support:

a. **Regarding the statement that "(t)o provide adequate support of PGE's Call Center Technology additional Cisco Networking expertise is required," how is PGE currently addressing lack of adequate support?**

b. **Will the addition of the FTE result in offsetting cost savings, i.e., reduced overtime? If yes, how is the cost savings reflected in the test year revenue requirement?**

Response:

a. The Interactive Voice Response (IVR) system interfaces with multiple systems that provide support and services to customers. Staff currently supporting the IVR is over capacity, resulting in delayed maintenance and patching. Existing support staff is limited, and support levels are often limited to the minimum possible levels.

b. Existing salaried staff often work extended hours in an attempt to maintain adequate support for the IVR. PGE does not expect any direct cost savings or offsets to result from adding this FTE.

May 4, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 513
Dated April 21, 2017

Request:

Regarding PGE 502, pg 2 - Specialist:

a: Is there a currently a need for on-site staffing beyond 40 hours work per week?

b. If the answer is yes, how is PGE is currently addressing inadequate support?

c: Will the addition of a new FTE result in offsetting cost savings, i.e. reduced overtime? If yes, how is the cost savings reflected in the test year revenue requirement?

Response:

a. As PGE moves to systems that are increasingly critical to field operations, the need for 24/7 support has increased. Both customers and field crews depend on the availability of IT systems to restore operations in the event of disruptions. This imperative drives a need for 24/7 on-site staffing to provide rapid response and resolution to system issues. Without the additional FTE to support this, IT will need to retain higher-cost contract resources to provide this capability.

b. IT staff currently provide limited after-hours support, including on-call support by staff that also work during regular weekly hours and 24-hour support, five days per week. By adding this new FTE to provide additional support, IT will be able to increase support hours to 24/7.

c. PGE does not expect any direct offsets or cost savings associated with adding this new FTE.

May 4, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 514
Dated April 21, 2017

Request:

PGE/502, p. 3 – Quality Assurance Analyst.

a. **Does PGE currently employ quality assurance analysts that support Business Intelligence, GIS, Finance and Human Resources?**

b. **How does PGE currently provide adequate quality assurance support to Business Intelligence, GIS, Finance, and Human Resources? For example, does PGE use overtime, contract labor, or allocate employees from other areas.**

c. **Regarding the statement "[t]he applications supported are complex and require highly skilled QA analysts"; please list all the applications referred to and the implementation (start) date of each application.**

Response:

a) PGE is currently supporting the Quality Assurance (QA) function for the systems mentioned in this data request by utilizing contingent workers. Supporting these applications requires a highly specialized skill set, both for application development and for testing. Because the role needs a skill set that is difficult to acquire via contingent workers PGE needs permanent QA Analyst support so it can retain the knowledge in house for long-term sustainability. For additional information please see PGE's response to OPUC Data Request 484, Attachment B, Tab "Position Breakout", cell F15.

b) As mentioned in part (a) above, to adequately support these systems, PGE is currently employing contingent workers to perform the required tasks. PGE leverages regular employees to provide periodic support to the contingent workers on an as-needed basis.

c) The applications referred in this data request and their implementation dates are:
   - Business Intelligence: Implemented in December 2011

- Peoplesoft Human Resources (HR) & Peoplesoft Finance:
  - Peoplesoft HR Implementation Date: November 2005
  - Peoplesoft Finance Implementation Date: April 2011
- Geographic Information System (GIS): Implemented in July 2015

May 3, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 515
Dated April 21, 2017

Request:

Regarding PGE/502, p. 3 – Quality Assurance, Release Manager: Regarding the statement "[c]urrent and future workloads make it clear that present staffing levels will be inadequate to provide the necessary level of accuracy and completeness that Release involvement delivers to the enterprise"; what is PGE's best projection of when current staffing levels will no longer be adequate?

Response:

The current staffing level in Information Technology is not able to support all the approved Operation and Maintenance (O&M) work and project activities in the Application Services area.

The O&M work and project initiatives include:
- Compliance deliverables;
- Process improvement initiatives;
- System upgrades; and
- Vintage (server refresh) efforts.

To mitigate the staffing shortage, PGE periodically pulls contingent workers into portions of these O&M work efforts in order to adequately staff these initiatives. Additionally, the current staff (both contingent workers as well as employees) works frequent overtime hours in order to accommodate the workload.

May 3, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 516
Dated April 21, 2017

Request:

Regarding PGE 502, pg 3 – Governance Risk Compliance System Support:

a. **What is PGE's projection of the reduction in vendor spend that will be associated with new FTE to support GRC tool? Is this reduction reflected in the test year revenue requirement?**
b. **Please describe in more detail the regulatory changes, enhancements and other uses for the GRC tool that caused PGE to reassess the need for a FTE to support the GRC tool.**

Response:

a. PGE is currently budgeted to spend $180,000 in vendor support costs in 2017. PGE anticipates the vendor support costs will increase to between $200,000 and $240,000 after the expansion and update of Governance Risk and Compliance (GRC) is complete. We expect that the GRC System Support FTE will reduce vendor support expenses by approximately $120,000. This reduction is reflected in the calculation of the 2018 test year revenue requirement.
b. The GRC tool is a software product designed to help companies manage compliance, meet regulatory requirements, and automate workflows to improve compliance efficiency.

   The GRC tool was implemented in IT to support North American Electric Reliability Corporation critical infrastructure protection (NERC CIP) requirements, perform and track security risk assessments and track IT SOX controls.

   Enhancements being planned for GRC are not driven by new regulations or changes but expanding the use of the project to other compliance areas or process areas for efficiency in IT. Such areas are:
   - Policy workflow management;

- Automated notifications and workflows for all compliance owners and documentation requests;
- Tracking of all control performance and automated reporting as well as expansion of the use of the GRC tool for Cyber Security controls framework and assessment.

May 3, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 517
Dated April 21, 2017

Request:

Regarding PGE/502, p. 3 – Compliance manager:

a. **Is PGE creating a new department that requires a manager?**
b. **Will the manager oversee both the IT compliance and disaster recovery departments? If yes, who is currently overseeing these departments?**
c. **Are the 5-8 FTE that the manager will oversee currently employed at PGE? If yes, who is the current manager for each of these FTEs?**
d. **In what circumstances will there be contingent workers? Will the contingent workers be allocated from other departments within PGE, or be temporary or contract labor?**

Response:

a. No, PGE will not create a new department. The Compliance Manger will be part of the Information Risk Management Department (Dept. ID 775) and will oversee the IT Compliance and Risk Management team.

b. Yes, the Compliance Manager will oversee both the Information Technology (IT) Compliance department and IT Disaster Recover department. The IT Compliance Department and IT Disaster Recovery Departments currently report to the Information Risk and Security Director. This has created a "span of control" issue where there are too many direct reports to be effective as this director also oversees two other teams (Energy Information Systems and Information Security Assurance) and will be taking on a new department (the Integrated Security Operations Center (ISOC)). PGE Internal Audit has recommended that the IT Compliance team have a direct manager so as to separate the responsibilities and minimize segregation of duty issues. Three additional employees will be moved to these teams as well. The Compliance Manager will oversee eight individuals.

c. Five of the FTEs are currently employed at PGE and report to the Information Risk and Security Director mentioned in part (b), above. Three more FTEs are being posted for hire in 2017. For additional information about the organizational structure of the IT department please see PGE's response to OPUC Data Request No. 521, Attachment 521-A.

d. Contingent workers are hired to support new or changing regulatory requirements that require temporary ad-hoc work to meet upcoming deadlines. They are also hired when extra regulatory testing or remediation activities need to take place in preparation for external audits. The contingent workers will be temporary or contract labor. This team averages two to four contingent workers per year over the last three years.

May 3, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 518
Dated April 21, 2017

Request:

Regarding PGE/502, p. 4 – Analyst IV, Sr Information Security: Will PGE terminate the use of the contractors that have "traditionally performed" the security testing that will be performed by two new FTEs? If yes, is the cost savings reflected in the test year revenue requirement? If no, please explain why not.

Response:

PGE currently utilizes four to eight contractor staff per year in the Information Security Assurance department. Two of these contractors will be terminated in 2018. Their cost savings are reflected in the calculation of 2018 test year revenue requirement.

May 3, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 519
Dated April 21, 2017

Request:

Regarding PGE/502, p. 4 – Analyst IV, Threat Analyst:

a. **Does PGE currently do threat identification, analysis, and response to new and emerging threats? If the answer is yes, will the currently used resources be freed up by addition of FTE?**

b. **Is there offsetting cost savings or benefits associated with hiring of new FTE, i.e., reduced overtime, re-allocation of current employees to different area?**

Response:

a. PGE does not consistently perform threat identification, analysis and response. When critical threats are identified, resources are reprioritized from existing work. As the frequency of these critical threats is rising, the reprioritization approach is no longer tenable or effective. No currently used resources are freed up by the addition of this FTE.

b. The benefits of adding this position are in the area of risk reduction. However, PGE does not expect hard cost savings after adding this FTE as this FTE will be devoted full time to a function that wasn't permanently covered before.

May 3, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 520
Dated April 21, 2017

Request:

Regarding PGE/502, p. 5 – Program Manager, ISP:

a. **Who is currently leading and facilitating implementation of multi-year information security roadmap?**

b. **Does PGE anticipate that employees currently working on implementation of information security roadmap will continue to work on this project in the future? Please explain.**

Response:

a. PGE's Information Security Program is currently being led by a combination of PGE's Cyber Security Director, multiple contract/temporary program managers, and project managers.

b. PGE anticipates that some employees currently working on the implementation of the information security roadmap will continue to work on the implementation, depending on their specific expertise. The roadmap is highly complex and consists of ten initiatives with multiple projects in some of the initiatives. Each of these projects may require different employees based on the specific project objective and skill requirements. The security-related employees requested as part of PGE's 2018 general rate case will fill gaps of skillset and labor supply that PGE currently does not have. These are the minimum FTEs required to support these initiatives past initial implementation and into regular operations mode. All other staffing needs will be filled by temporary contract FTEs.

May 3, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 521
Dated April 21, 2017

Request:

Regarding PGE/500, Henderson-Hosseini- Anderson/16-21 and PGE/502, pp. 4-5:

a. **Please provide an organization chart that shows the ISOC and any departments that will house the new 22 FTEs and how and where these departments fit within the PGE organization.**

b. **Will the ISOC include any current PGE employees? If yes, please explain.**

c. **How many employees will be housed in ISOC, assuming all nine FTEs identified in PGE/502 are hired.**

d. **Will any current PGE employees be assigned to work on IAM? Please explain.**

Response:

a. Attachment 521-A provides the Information Technology and Information Systems organizational chart.

b. As noted in the organizational chart (Attachment 521-A), the Integrated Security Operations Center (ISOC) department will include four existing employees who make up the current Security Operations team.

c. Initially, fourteen employees will be housed in the ISOC. One manager, twelve staff and one liaison from corporate security to assist with security incident response. The nine FTEs referenced above are the ISOC manager and eight of the twelve staff.

d. Yes, one current developer will be assigned to work on the Identity Access Management project (IAM). The three new roles will help support the multiple IAM software products during and post implementation.

UE 319

Attachment 521-A

Provided in Electronic Format only

IT/IS Organizational Chart

DR 521

- **Information Technology** — VP of IT, CIO
  - **Office of CIO** — Director
    - **Business Relationship Mgmt** (includes Business Analysts)
      - Analyst IV, Program Bus Anslyst
      - Analyst III, Identity / Access Bus Analyst
  - **IT Applications Director** — Director
    - **Application Shared Services**
      - Analyst IV, Applications Developer IAM
      - Analyst IV, Applications Developer IAM
  - **Information Risk & Security** — Director
    - **IT Compliance & Risk Mgmt** — Manager
      - **IT Disaster Recovery**
      - **IT Compliance**
        - GRC System Support Analyst
        - Analyst IV, Role Manager, RBAC
        - Analyst IV, Governance, Access & Rept.
        - IT Risk & Governance Analsyst
        - IT CIP Compliance Analyst
        - IT SOX Compliance Analyst
    - **Information Security Assurance** — Manager
      - AnalystIV, SR Information Security
      - Security Risk Analyst
      - Sr. Security Testing Analyst
      - Sec. Testing Analyst
      - Sec. Testing Analyst
      - AnalystIV, SR Information Security
      - Analyst IV, Sec. Assurance 3rd Party Risk
      - Analyst IV, Threat Analyst
    - **Integrated Security Operations Center (ISOC)** — ISOC Manager
      - Analyst, ISOC
      - Analyst, ISOC
      - Analyst, ISOC
      - Analyst, ISOC, GEN
      - Analyst, ISOC
      - Specialist, ISOC, T&D
      - Specialist, ISOC, T&D
      - SR Sec. Specialist
      - Sec. Specialist
      - Sec. Specialist
      - Sec. Specialist
    - Program Manager, ISP

Existing department
Newly formed department
Orange Text is new position
Black text are existing FTE or those being transferred into dept.

Spec V, Security Monitoring
Admin, T&D Substation Support
Manager, T&D OT Support Services

The above are positions that will be embedded throughout PGE departments outside of IT but supporting Information Security program.

May 3, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 522
Dated April 21, 2017

Request:

Regarding PGE 500, Henderson-Hosseini-Anderson/18:

> **PGE notes that "primary implementation" of initiative described at pp 16-21 of PGE/500 will begin in 2017 and continue through 2021. Does PGE plan to hire FTEs for initiatives in addition to 22 FTEs after 2018?**

Response:

PGE is currently designing detailed planning for initiatives beyond 2018. We expect to hire an additional 6-10 FTEs to support these initiatives (beyond the initial 22).

Hiring will only take place for FTEs that are required to support initiatives after implementation. All other requirements will be completed through contract and temporary hires.

May 3, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 523
Dated April 21, 2017

<u>Request:</u>

Regarding PGE/500, Henderson-Hosseini-Anderson/16-21:

a. Please explain how PGE will allocate current FTEs that are performing security tasks that will be performed by 22 FTEs described in testimony for ISOC and implementation of IAM and other security initiatives described in referenced testimony?
b. Will the addition of the 22 FTEs reduce the need for overtime or contract labor? If yes, are cost savings reflected in test year revenue requirement?

<u>Response:</u>

a. Please see Attachment 521-A for the Information Technology and Information Systems organizational chart. All orange positions indicate the 22 security related positions and how they are allocated as well as the Compliance Manager and GRC Support Person.

b. The addition of the two Analyst IV, Sr. Information Security FTEs is expected to reduce contract labor. For more details about these two FTEs please see PGE's response to OPUC Data Request No. 518. The other 20 are new FTEs that will be performing new work. No other contract or overtime labor will be reduced.

   The cost savings expected from adding these two positions are reflected in the calculation of 2018 test year revenue requirement.

May 19, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 558
Dated May 9, 2017

Request:

Referring to the Company's UE 319 excel work sheet 2014-2018_FTE_W&S_By Operation,RC & Class_01-30-17.xls, at 13-18, UE 294 *I* PGE *I* 500, Barnett-Jaramillo/16-17, UE 294 *I* PGE *I* 600, Lobdell - Henderson - Tooman *I* 28 -36, UE 294 *I* PGE *I* 800, Nicholson - Bekkedahl *I* 12, UE 294 *I* PGE *I* 900, Stathis - Dillin *I* 8-13.

Please provide a narrative explaining why the Company's FTE count, including the FTE allocated to the CET deferral, has increased by 302.2 FTE in 2018 over 2016. In the response, please include:

a. Any and all studies or similar deliverables, whether conducted by consultants or internally, initiated from 2014 to present such as benchmarking studies, management reports, variance analysis, cost report cards, etc. that quantify the gained efficiencies since 2014 and provide evidence that these programs and initiatives are benefiting customers.

Response:

Narratives explaining the referenced increase in PGE's FTE count have been provided in UE 319 testimony, supporting exhibits, and in numerous responses to data requests. All references to this information is summarized in Attachment 558-A. FTE increases by project will also be provided in PGE's response to OPUC Data Request No. 561, Attachment 561-A.

a. PGE has provided significant detail in recent years to quantify benefits to customers for the programs, systems, and initiatives being implemented. We summarize these benefits as follows:

1. In PGE's 2014 general rate case (GRC – Docket No. UE 262), we identified significant savings from improvement initiatives. These savings were summarized in PGE Exhibit 201 (provided as Attachment 558-B), which also lists the testimony reference where the savings were discussed in more detail. PGE Exhibit 200 (UE 262, pages 6-10) also included a summary description of the $15.6 million in annual, on-going savings, which is provided as follows:

PGE has numerous improvement initiatives completed or underway as a result of our benchmarking activities, process improvements, or other activities. Some of these major initiatives are:

- Transmission & Distribution (T&D) Transformation is an effort to improve work processes and leverage technology to improve safety, accountability, standardization, productivity, and efficiency in transmission and distribution. The transformation program projects O&M annual savings of $3.4 million in 2014. Details can be found in PGE Exhibit 800, Section II.
- Financial Systems Replacement Project (FSRP) replaced PGE's obsolete 26-year old Masterpiece system with a new financial system that enables streamlined workflow and automation of many manual processes. Examples of streamlined workflow include:
    - 40% reduction in cash management processing time; and,
    - Automation of 80% of book-tax adjustments.

  FSRP, in conjunction with Lean process analysis, allowed for Finance and Accounting (F&A) to realize efficiencies through a net reduction of approximately 11 Full Time Equivalents (FTE) through 2012 and another 4.3 FTEs by 2014. Details can be found in PGE Exhibit 1000, Section II, Part A.
- Procurement Efficiencies via Strategic Sourcing consists of performing spend analysis by utilizing our new financial system (FSRP), identifying business requirements, understanding the marketplace, developing a supply category strategy, evaluating and selecting suppliers, negotiating agreements, developing scorecards to measure supplier performance and then repeating the process to drive continuous improvement. In 2012, PGE negotiated over $7.6 million of O&M cost savings and $2.6 million of O&M avoided costs that span multiple years (i.e., $1.4 million in 2012, $1.2 million in 2013, $1.1 million in 2014, and the remaining $6.5 million after 2014). Details can be found in PGE Exhibit 1000, Section II, Part A.
- Lean Processing in Human Resources – Lean processing is a process improvement methodology that focuses on removing "waste" from processes so that efficiencies in time and resources can be achieved. Waste can be anything from wait time, to errors and re-work, to extra processing. As processes are improved, productive resources can be reallocated to higher-value activities. PGE's Human Resources (HR) has completed 20 Lean processes with more in progress. Details on HR Lean processing efforts can be found in PGE Exhibit 1000, Section II, Part C.
- Employee Benefit Provision Mitigation – Health care reform will have a significant impact on medical plan design and cost as it evolves over the next few years. PGE is monitoring health care reform, and we are evaluating

possible future changes to existing benefit plans. In preparation for reform, we have modified many benefit provisions to offset the full effect of increases in benefit costs while maintaining an effective level of benefit support for employees. Some of the benefit changes are:

- Increasing deductibles and co-pays;
- Adding additional coinsurance to various plans; and,
- Offering high deductible plans by each vendor in addition, not in lieu of other offerings.

PGE evaluates if a change in benefit options offered is prudent and if further cost shifting to employees, in terms of out-of-pocket contributions, deductibles and choices of care are appropriate. See PGE Exhibit 500, Section IV for more details on how PGE is working to mitigate benefit cost increases.

- myTime is a web based time collection system (TCS) that will increase accuracy and reduce resources spent on time-keeping processes and payroll. myTime will replace the currently obsolete paper TCS in 2013. PGE projects a reduction in payroll costs of $1.0 million, which is reflected in wages and salaries in both 2013 and 2014. myTime is explained in more detail in PGE Exhibit 1000, Section II, Part C.
- Information Technology (IT) Vision Design is a roadmap of 15 initiatives directed at improving IT's effectiveness, capabilities, and efficiency over the next three years. Each initiative encompasses one or more of the following six foundational principals: partner with the business; eliminate complexity; source strategically; standardize IT process/procedures; build a strong workforce; and, meet increasing service expectations. Through the 15 initiatives, IT will be able to continue supporting PGE's growing need for technical infrastructure and services while maintaining a relatively flat IT employee count. From 2011 through 2014, we project a net reduction of 7.8 IT FTEs. See PGE Exhibit 600, Section III, Part B for details.
- Generation Excellence. In 2006, PGE's generation organization established the Generation Excellence initiative to focus on improvement efforts such as safety, employee performance, process improvements, and reliability. Generation Excellence has continued to evolve with the establishment of Reliability and Maintenance Excellence (R&ME), which is a comprehensive approach to reliability and maintenance; it encompasses, and better aligns, several sub-initiatives including Reliability Centered Maintenance (RCM) and utilization of our Enterprise Work and Asset Management System (Maximo). R&ME is plant specific and each plant is anticipated to have their strategy in place by the end of 2013. For more detail see PGE Exhibit 700, Section III, Part A.

2. In PGE's 2015 GRC (UE 283), we updated the UE 262 savings plus identified incremental amounts that totaled to $23.4 million in cumulative annual savings. We summarized these benefits in PGE Exhibit 707 (UE 283) and provide them as Attachment 558-C. Additional detail regarding benefits from the Transmission and

Distribution Transformation project (part of PGE's 2020 Vision program) can be summarized as follows:

Maximo, Mobile & Scheduling improves employee safety, heightens accountability, and standardizes our processes, which improves productivity and efficiency in the following ways:

- Employee Safety: With mobile devices in the hands of field workers, PGE is able to track work processes being performed and logged when a worker is completing an inspection or doing maintenance work in real-time. The Mobile & Scheduling tools improve employee safety by providing PGE with real-time updates on the location of our field workers and provide a communication link in the field.
- Accountability: Maximo, Mobile & Scheduling provides teams with better accountability data and production information. Supervisors have the ability to review the current status of field crews and details of assigned work. Field workers can update the status of their work, resulting in real-time data for schedulers and supervisors. By having an enterprise wide work and asset management system, we have a clearer, more integrated view of how and where work is being performed within PGE and how to more effectively employ our company personnel and assets.
- Productivity: Productivity should increase as work orders are created in Maximo, and electronically routed and dispatched along with the field workers (including contractors) who are closest to the worksite and possess the appropriate skillset(s) to perform the work. The new technology provides workers with real-time customer and asset information. Mobile & Scheduling tools provide:
    - Optimization of scheduling to reduce travel time and crew costs;
    - An opportunity to re-optimize work schedules dynamically, as needed;
    - Real-time dispatching of work details and status updates; and
    - Automatic asset information updates and work order closures.
- Efficiency: In addition to allowing PGE to track purchasing of inventory stores and materials for work orders, Maximo also provides PGE with the ability to track the rate of use of inventory to optimize stock levels. PGE's goal is to maximize availability of items required for upcoming work while also reducing or removing, as may be appropriate, inventory that is required less frequently or has become obsolete. The reduction in inventory is also expected to reduce the carrying costs associated with that inventory.

3. In PGE's response to OPUC Data Request No. 489, part d, we identified an additional $3 million to $5 million in savings associated with PGEs' customer engagement transformation program (CET) based on:

    - A reduction of 33 FTEs between 2013 and 2016, which has allowed the customer service organization to reduce its FTE count from 407 in 2012 to the projected

382 in 2018 with some offsetting increases due to other factors such as customer growth.

- An additional 10.9 FTE reduction is projected in 2019/2020 after the system is stable and operating.
- Approximately $1.0 million in non-labor cost reductions due to the paperless billing program. This savings will grow as customer participation in the program increases.

4. In addition to the savings listed above, PGE had also identified additional savings as discussed in the following proceedings:

- In UE 294 (2016 test year GRC, PGE Exhibit 700), PGE reduced its annual production O&M by $4.5 million based on a change in the maintenance and repair program for the Biglow Canyon wind farm.
- In UM 1756, PGE deferred for later refund an annual $1.3 million for the reduced debt cost associated with the issuance of $140 million in debt in January 2016.
- In UE 294 (2016 test year GRC, PGE Exhibit 400), PGE discussed the benefits associated with more frequent scheduling and dispatch of PGE's plants. At that time, managing the intra-hour variability of our wind resources on a 15-minute basis (i.e., 30/15 committed scheduling under BPA's Variable Energy Resource Balancing Service) reduced PGE's initial 2016 power cost forecast by approximately $2.9 million. In UE 319, PGE identified the benefits of moving off of 30/15 committed scheduling as an additional $2.1 million decrease to PGE's 2018 power cost forecast, net of costs associated with incremental reserve needs to fully self-integrate PGE's owned wind resources.
- In UE 308 (2017 power cost AUT filing, PGE Exhibit 400) PGE discussed the benefits associated with joining the Western energy imbalance market (Western EIM). The Western EIM is expected to produce several benefits, including sub-hourly dispatch savings, flexible reserve savings, and reliability benefits. Based on a study by Energy + Environmental Economics (E3 – provided as PGE Exhibit 402 in UE 308) the gross savings associated with these benefits was estimated to be $3.5 million in a 2020 base scenario. In UE 319, PGE provided an updated E3 study (provided as PGE Exhibit 303), which estimated $5.2 million for similar gross benefits in a 2018 base scenario. Including all costs and benefits associated with Western EIM participation, PGE's net benefit is approximately $1.0 million in 2018 (see Table 1 of PGE Exhibit 300).
- In UE 189, PGE's submitted its final report to the Commission (November 2, 2012) on actual operational savings derived from PGE's advance metering infrastructure system. The report stated that annual savings totaled $19.0 million and were expected to increase in 2013.

5. Additional discussion regarding other benefits to customers (i.e., not in the form of hard savings) has been provided in the following testimony as well as regular presentations to the OPUC Staff in advance of each of the past four general rate cases (GRCs).

    i. The 2020 Vision project has been discussed in Information Technology testimony in each of the last five GRCs (PGE Exhibit 600, UE 215; PGE Exhibit 600, UE 262; PGE Exhibit 700, UE 283; PGE Exhibit 600, UE 294; and PGE Exhibit 500, UE 319). Detail regarding benefits can be summarized as follows (see PGE Exhibit 600, UE 215, pages 24-28):

        - Current technology obsolescence – Many of the systems that PGE plans to replace have been in service for many years and are either no longer supported by the vendor or will not be supported in the near future. When systems are no longer supported, upgrades and enhancements are no longer provided by the vendor to meet new requirements, patch security threats, or fix bugs. At that point, PGE would have to perform this work in-house at significant cost and risk.

          For example, PGE's financial system is 26 years old, the vendor is no longer making enhancements, and we need a system that can accommodate the International Financial Reporting Standards (IFRS) that are currently expected to be required by 2012 (i.e., 2014 but with two prior years of detail). PGE can incur additional costs to upgrade these legacy systems with the new requirements but this means we would not have ongoing vendor support as the technology and user requirements continue to change.
        - Operational efficiencies through process improvement – inefficient and redundant processes will be identified and improved, thereby increasing operational efficiency. Examples of benefits include:
            - Elimination of manual processes, reduction of redundant work, improved workflow, and more efficient reconciliation. In addition, PGE expects to: 1) have a more effective capital and O&M budgeting process, 2) have enhanced ability to forecast multiple scenarios and analyze data, 3) capture PGE's financial commitments and expected cash flows automatically, and 4) strengthen our internal controls by automating current manual controls.
            - Optimization of resources across maintenance, construction, and inspection groups. Currently, resource assignments are assembled manually and dispatched by individual workgroups, limiting the ability for workforce leveling or resource optimization across the organization. A fully integrated work and asset management system, built on standard business processes, will reduce the amount of manual reconciliation and handling required for scheduling and dispatch. In addition, it will enable PGE to compare and contrast similar work activities by crew or region.
        - Improvements in customer service – Customer information can be connected to: 1) the assets associated with providing electric service (i.e., transformers, poles, wires, meters, etc), and 2) the PGE resources responsible for building,

maintaining, and repairing those assets. For example, an Asset Management system that is fully integrated with GIS and Outage Management applications, in conjunction with our Smart Meters, can create a foundation for future projects to allow customers to access their service information and the status of restoration efforts in real-time.

Currently, there is no intelligent connectivity model for PGE's distribution system and outages are determined via "roll ups" of circuit maps. This results in additional time spent diagnosing the outage, incomplete knowledge of the outage boundaries and affected customers, and less than optimal crew dispatching for restoration efforts.

- Improved asset utilization – Currently, PGE does not have the means for a consistent asset management strategy or process, across organizations and individual work groups, to determine how best to utilize our assets. Because departments independently conduct narrowly scoped work on the same assets, without a holistic view of the work required, some re-work and revisits to any given asset may occur. With up-to-date technologies and standardized processes PGE can benefit from "just in time" inventory and we will have more accurate information to identify when critical assets need replacing rather than use a time-based replacement strategy.
- Smart grid connectivity – With PGE's current fragmented systems, smart grid data will not be available across applications and cannot be fully utilized. Consequently, PGE's current technology will become a bottleneck to realizing future smart grid potential. By implementing the 2020 Vision program, with process improvement and standardization, PGE can use real-time, smart grid information to optimize PGE's power delivery system (e.g., transformers and other assets) and realize more dependable and more rapid outage identification.
- Knowledge transfer – Much of PGE's knowledge of operational practices resides within the individuals currently performing the work. Over the next five to ten years, we anticipate that a significant percentage of our IT workforce will retire. The effort required to migrate work processes from legacy applications to new systems offers a unique opportunity to address how we capture process knowledge and train new employees, so that as much as possible, our historical contexts, policies, and ways of working will not be lost in the labor transition.
- Time to complete – Because the systems will take up to seven years to fully implement and given the needs/benefits identified above, PGE believes it is inappropriate to delay the program beyond the current schedule.
- Based on the last four years of historical costs, PGE estimates that without implementing the proposed projects, the cost of maintaining and upgrading PGE's existing systems over the next five years will be approximately $44 million. This would maintain current functionality and business processes and provide little or no additional business value, while at the same time would:
  - Leave PGE unable to respond to increasing demands for real-time information, changing customer needs, and increasing regulatory requirements;

- Impair PGE’s ability to pursue business process improvement efficiencies;
- Require continued significant investment in IT integrations of disparate systems in an attempt to provide the seamless flow of data across applications, such as the data required for and provided by the Smart Grid;
- Put PGE at risk of losing valuable knowledge currently embodied in long-time employees’ understanding of how to work across disparate information systems;
- Weaken PGE’s ability to attract and retain new talent to replace retiring workers;
- Inhibit PGE’s ability to leverage the capabilities of Smart Grid technologies currently being implemented; and
- Be analogous to paving cow-paths rather than investing in a modern freeway system.

ii. Information Security provides significant benefits but primarily in the form of avoiding the increasing risk of sophisticated data breaches, data loss, or compromised operations by hackers who could exploit vulnerabilities in PGE's cyber and critical infrastructure assets. We would also face financial penalties due to non-compliance with legal and regulatory requirements. In short, PGE cannot afford to defer this work. The study used to identify the security measures and initiatives from which PGE developed its Information Security Roadmap was provided in confidential work papers to PGE Exhibit 500, UE 319 (see “Risk-based Prioritizations and Updated Security Roadmap”).

iii. Customer Engagement Transformation (CET) program became the last portion of 2020 Vision and was discussed separately in PGE Exhibit 900, UE 262; PGE Exhibit 1000, UE 283; PGE Exhibit 900, UE 294; and PGE Exhibit 900, UE 319. Benefits from CET include:

- Provide several enhancements that are responsive to customer needs, including the ability for customers to:
  - Make one-time check payments over the phone; currently customers are redirected to the IVR system or the PGE website to make the payment.
  - Enroll in Auto Pay or update bank account information over the phone.
  - Choose the specific date their bill will be due, instead of the bill cycle (date range), helping customers better plan and manage their cash flow.
  - Enroll in the Preferred Due Date program with fewer restrictions making it more accessible to customers who could benefit the most.
  - Keep their new account number permanently (when new systems are implemented), even when they move to a different address within PGE’s service territory.
- Support more varied pricing options compared to what is available with our current system.
- Replace systems that have become technically and functionally obsolete, are not suited for emerging smart grid requirements and changing customer

expectations, and must be replaced if PGE is to remain responsive to customers' needs, expectations, and preferences.

iv. Transmission and Distribution (T&D) strategic capital improvements relate to customer-driven capital work and efforts to improve the T&D system to: 1) replace or upgrade equipment nearing the end of its life; 2) redesign portions of the system to improve reliability; and 3) better prepare for earthquakes, cyber-attacks, and other threats. This effort was guided by a third-party assessor, Black & Veatch (B&V) that PGE hired to review our T&D asset management practices and capabilities. B&V's assessment of T&D – a Publicly Available Specification 55 (PAS-55) – is provided in confidential work papers to PGE Exhibit 800, UE 319. Based on this assessment, PGE created the Strategic Asset Management department (SAM) to develop an annual T&D risk assessment and associated portfolio of recommended risk reduction projects. The objective of SAM's methodology is to consider the negative impacts of service failure on:

- System reliability;
- Public and worker safety;
- Environmental stewardship; and
- Efficient expenditure of funds.

SAM identifies system improvements that demonstrate <u>maximum value to customers in terms of risk reduction</u>. The types of projects include:

- Asset replacement by proactively replacing infrastructure that is operating beyond its life and thus creating reliability, safety, environmental, and cost threats for customers;
- System reconfiguration by shifting loads in the system or reconfiguring system designs to better manage load and can reduce the impacts of service failures on customers should they occur; and
- Grid modernization by installing new types of advanced technologies that can help PGE increase reliability and meet new customer demand (e.g., PGE's Smart Grid initiatives).

UE 319

Attachment 558-A

Provided in Electronic Format only

FTE Data Provided in UE 319 Testimony, Exhibits, and Responses to Data Requests

UE 319

Attachment 558-B

Provided in Electronic Format only

UE 262; PGE Exhibit 201

UE 319

Attachment 558-C

Provided in Electronic Format only

UE 283; PGE Exhibit 707

CASE: UE 319
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1106

Exhibits in Support
Of Opening Testimony

June 16, 2017

Exhibit 1106 is confidential and

Is subject to Protective Order No.17-057

CASE: UE 319
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1200

Opening Testimony

June 16, 2017

Q. Please state your name, occupation, and business address.

A. My name is Rose Anderson. I am a Utility Analyst employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. What is the purpose of your testimony?

A. I discuss PGE's proposed lighting expenses and related FTE increase.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits:

Exhibit 1201 — PGE Responses to Staff DR Nos. 527 and 367.

Q. Have you prepared a Witness Qualifications Statement?

A. Yes. My Witness Qualifications Statement is included as Exhibit 301 to PGE's NVPC filing in UE 319.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1: LIGHTING AND MISCELLANEOUS SCHEDULES

Q. Please provide background on PGE lighting expenses.

A. PGE provides outdoor "lighting service" to residential, commercial and industrial customers and to municipalities and agencies of state and federal government. Standard lighting service for customers other than municipalities and government agencies is provided under Schedule 15.

For Schedule 15 service, PGE provides the luminaires and poles and maintains both. Charges under Schedule 15 depend on the type of luminaire and the type of pole.

PGE provides standard outdoor lighting service to municipalities and government agencies under Schedule 91 Street and Highway Lighting Standard Service (Cost of Service) and Schedule 95 Street and Highway Lighting New Technology (Cost of Service), which provides the lighting service using new technology such as LED lights.

There are three options for pole and luminaire ownership in Schedule 91. Each option is billed differently depending on the services required from PGE. Under Option A service, PGE owns and maintains the poles and luminaires and includes a rental charge to customers. Under option B, the poles and luminaires are customer owned, but maintained by PGE. Under Option C, customers own the poles and luminaires and maintain them. PGE imposes a kWh energy charge per month. This kWh energy charge has three components: power supply, transmission and distribution.

Schedule 95 charges are similar, but there is no Option B service. For lighting service with LED lights, the Company does not offer maintenance service for customer-owned luminaires and poles.

In previous PGE rate cases, PGE's lighting model assumptions and inputs have been contested and discussed in workshops. For example, in 2010 in Docket No. UE 215, PGE and the City of Portland stipulated to workshops with lighting customers to address issues including maintenance practices and policies. In 2013 in Docket No. UE 262, parties stipulated to the resolution of several street lighting issues. The parties agreed that (1) maintenance costs of associated circuits will continue to be assigned directly to the maintenance prices for Schedule 91 Option A and B, Schedule 95 Option A and Schedule 15 prices, rather than recovered through distribution charge as proposed in PGE's initial filing, (2) the stipulated rate of return would be applied to lighting pole and investment prices, and (3) Option B rates would be calculated using a 0.2 percent pole replacement rate.[1]

PGE explained to Staff in a recent conference on lighting issues that there have been no major changes to the model forecasting lighting expenses since PGE's previous rate case Docket No. UE 294. For purposes of this case, PGE updated the UE 294 model using data from 2016.

[1] Order No. 13-459.

Q. Is PGE's current lighting model consistent with the parties' agreement in UE 262?

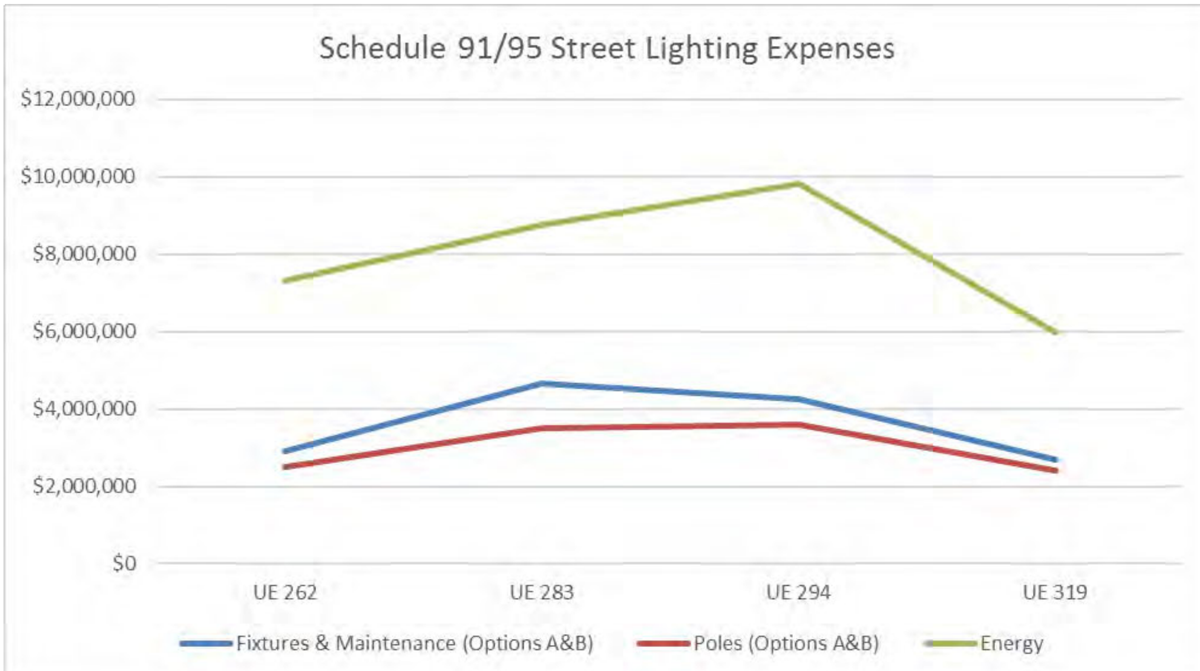
A. Yes. The maintenance costs of associated circuits are assigned directly to maintenance prices for Schedule 91 Options A and B, Schedule 95 Option A and Schedule 15, rather than recovered through distribution. Also Option B pole prices are calculated using a 0.2 percent replacement rate.[2] The Cost of Capital used for lighting pole and investment prices in UE 319 workpapers is 7.14 percent. Staff recommends updating this value after a Cost of Capital is decided for UE 319.

Q. How have PGE's lighting expenses changed since the last PGE rate case?

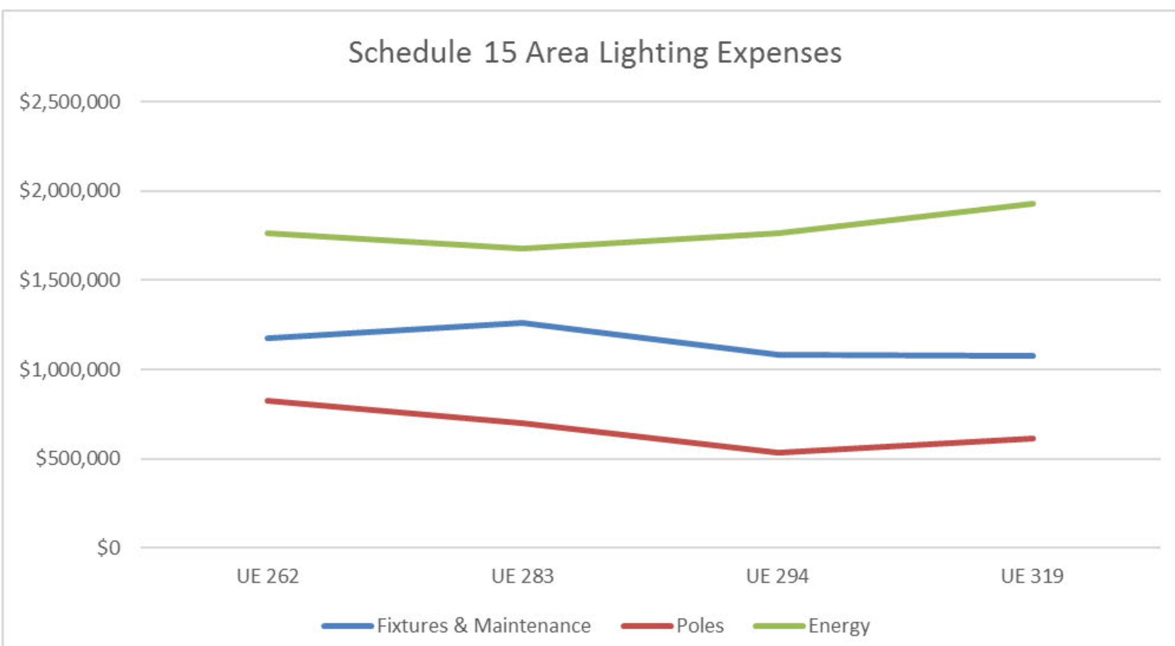
A. PGE's lighting expenses have increased modestly and in some categories have decreased since the UE 294 rate case in 2015. The following graphs show the lighting expenses included in rates in previous rate cases along with projected expense for this docket.

[2] Staff/1202, Anderson/20, PGE response to OPUC DR 367.

Graph 1.



Graph 2.



ISSUE 2: LIGHTING-RELATED FTE INCREASE

Q. What increase in FTE is associated with lighting?

A. PGE has included the cost of three new FTE positions in the Outdoor Lighting department. PGE justified the need for three new FTE positions in its response to OPUC Staff DR No. 527, explaining that the increase is intended to help the department take on the design of all "damage claims" jobs, reduce the time to complete lighting jobs, and manage two major projects.[3] The department also anticipates three retirements by the end of 2018.[4]

Q. Does Staff recommend any changes regarding FTE increases for lighting?

A. Yes. Staff recommends eliminating PGE's proposed increase of three FTEs for purposes of establishing PGE's 2018 Test Year expense. A December 2015 presentation to PGE officers anticipated one retirement during 2017 and two retirements during 2018.[5] The presentation requested an increase of two FTE in the Outdoor Lighting department. However, the presentation explained that the increase in FTEs would "roll back to current level in 2018/2019" because of the retirements.[6] Because the department anticipates starting the year 2018 with two additional FTE and returning to zero additional FTE after the two scheduled retirements, Staff proposes including no incremental FTEs in rates for the 2018 Test Year.

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[3] Staff/1202, Anderson/1-2, PGE Response to Staff DR No. 527.
[4] Staff/1202, Anderson/14, PGE Response to Staff DR No. 527, Att. C.
[5] Staff/1202, Anderson/14, PGE Response to Staff DR No. 527, Att. C.
[6] Staff/1202, Anderson/14, PGE Response to Staff DR No. 527, Att. C.

Q. Please summarize your adjustment.

A. Staff's recommends removing the three incremental FTEs PGE proposes to add to their Outdoor Lighting department. The effect of this adjustment to PGE"s Test Year expense is included in the FTE adjustment in Staff/400.

CASE: UE 319
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1201

Exhibits in Support
Of Opening Testimony

June 16, 2017

May 8, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 527
Dated April 24, 2017

Request:

Please provide any studies or workpapers supporting the reason for the FTE increase in:

a. **Service and Design Coordinators for lighting, as described on PGE/802, Nicholson – Bekkedahl/8**
b. **"Lighting Materials Project" as described on PGE/802, Nicholson – Bekkedahl/1.**
c. **Any other FTE increases in PGE's lighting-related retail services.**

Response:

There are three incremental lighting-related FTEs requested, two Service and Design Coordinators (SDC), also known as Lighting Design Project Managers (LDPM), and one Lighting Materials and Project Manager (LMPM).

PGE provides the following to support these FTEs:

a. Attachment 527-A is a memo to support the two SDCs (or LDPMs in the memo). Specifically, one SDC will maintain the Outdoor Lighting Services (OLS) to Transmission and Distribution (T&D) ratio. This SDC will allow better coordination between OLS and T&D designers to help reduce the duration of lighting jobs. The second SDC will manage two major projects: McLoughlin Boulevard Street Improvement Project for Clackamas County and converting cities from Option B to Option C streetlighting. In addition, PGE would like to update the position description for the SDCs, as the need for this role has changed since Exhibit 802 was filed. This will not result in a change in FTEs. We will make an update in our rebuttal testimony. The updated SDC position description is:

> "There are two Service and Design Coordinators (SDC) needed due to increased customer demand. An SDC is a Project Manager position, which is responsible for supplying residential development and municipality lighting designs/work orders for new street lighting required for occupancy."

These positions were filled in April 2016.

b. Attachment 527-B is the New Position Request form for the LMPM. In addition, this FTE is necessary to cover the 14% increase in lighting design job volume, discussed below. This position has not yet been filled.

c. Non-Applicable.

Attachment 527-C is a December 2015 PowerPoint presentation to PGE's officers on OLS's Strategic Roadmap. The FTEs requested are necessary to support the issues addressed in this presentation, primarily:

- The increase in workload – This department has experienced a significant increase in workload (e.g., there has been an increase of approximately 14% due to OLS taking on design of all Street and Area Light Damage Claims jobs) seen in Table 1, below. In addition, there are three major projects this department is involved in, which include the two listed earlier and City of Portland 240V Underground Repair Project;
- To decrease the backlog of streetlighting jobs – the number of streetlighting design jobs (municipality and developer driven) over 60 days without completed design has declined from 210 in January 2016 to just over 180 as of April 2017; and
- Succession Planning – There are three expected retirements in 2018-2019. These positions are necessary to provide a smooth transition of knowledge in the department.

Table 1: Annual Lighting Jobs Approved (Designed)

Jobs	**2015**	**2016**	**2017***	**2017 Projection**
Area Light Construction Jobs	327	280	97	291
Street Light Construction Jobs	349	323	113	339
Street Light Damage Claims Jobs	150	185	90	270
Total	**826**	**788**	**309**	**900**

*Year-to-date as of April 2017.

UE 319

Attachment 527-A

Provided in Electronic Format only

Memo to support LDPMs – January 12, 2016

UE 319

Attachment 527-B

Provided in Electronic Format only

New Position Request - 2017 Budget (LMPM)

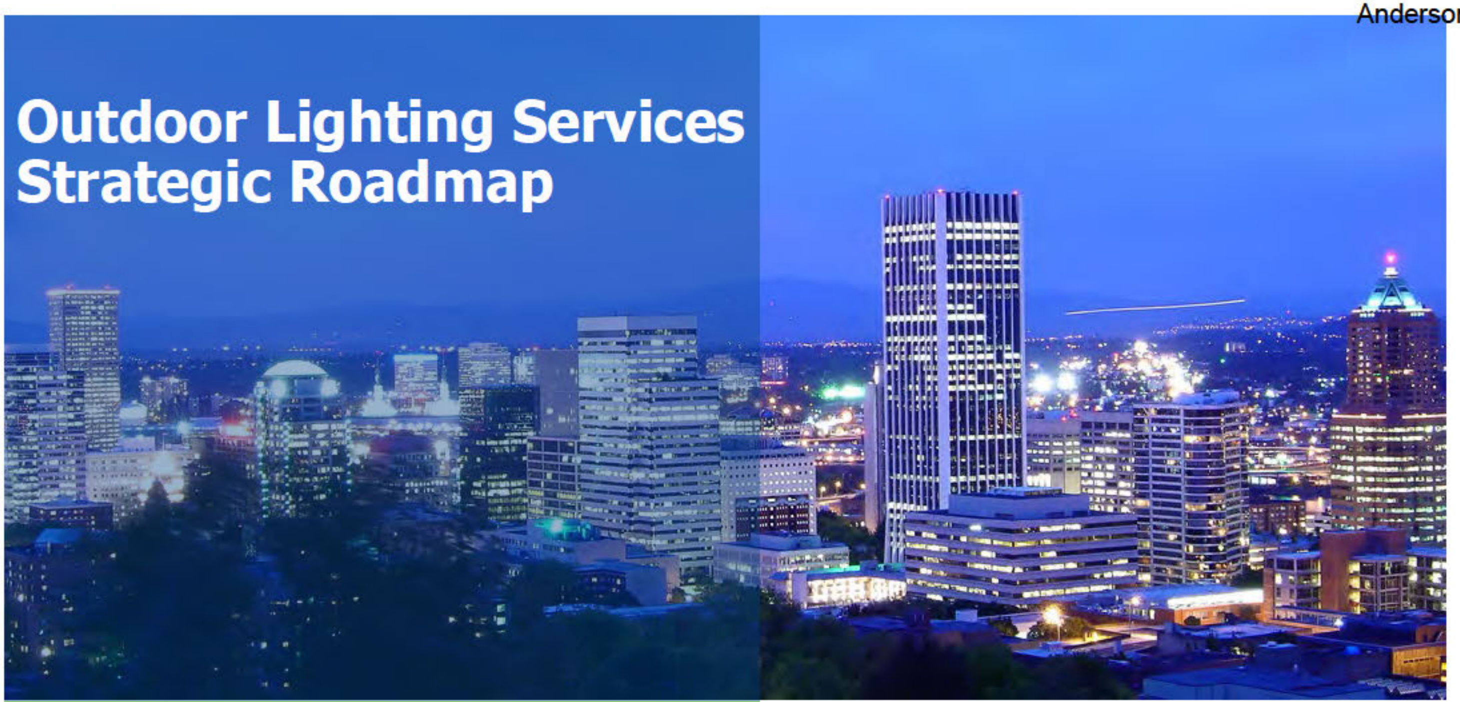
UE 319

Attachment 527-C

Provided in Electronic Format only

Outdoor Lighting Services Strategic Roadmap – December 2015

Outdoor Lighting Services Strategic Roadmap

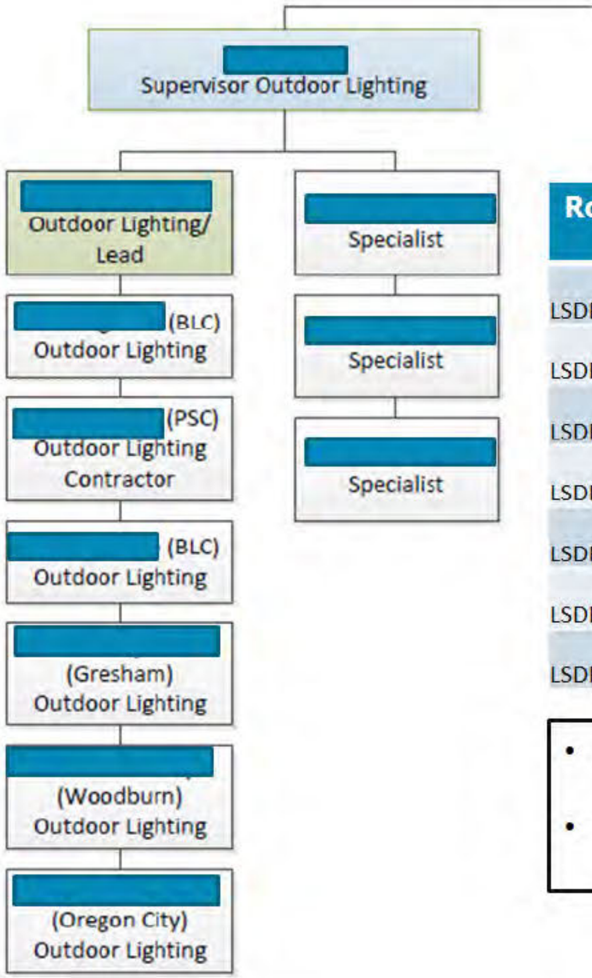


December 2015

Portland General Electric

Outdoor Lighting Org Chart

Portland General Electric



Role	Employee	Anticipated Retirement Year
LSDPM LEAD	[redacted]	2017
LSDPM	[redacted]	2018
LSDPM	[redacted]	2018
LSDPM	[redacted]	
LSDPM	[redacted]	
LSDPM	[redacted] (Contractor)	July 2016
LSDPM	[redacted] (New Hire)	

- FTE Count remains flat from 2009 to present
- Within 3 years we will need to replace 4 of 7 LSDPMs, 3 of which are the longest tenured LSDPMs.

Customer Service
Municipality and Developer Driven Jobs

- Approximately **50%** of all lighting design work is for developers on new subdivisions
- Average time from assignment to job construction of streetlighting design jobs (municipality and developer driven) is **4 months**
- Streetlighting design jobs (municipality and developer driven) over 45 days without completed design is **over 150**
- Year to date, **25%** of all Streetlighting design jobs (municipality and developer driven) are taking over **60 days to design**
- Timelines for design and construction are equally dependent on both T&D and OLS. Increasing production of one component without the other in today's regulated environment will not meet developers needs in regards to overall project completion.
- OLS to T&D Design ratio has been approximately 20%. T&D's future FTE count will increase by approximately 5 FTEs

Customer Service
Individual Customer and Claims Jobs

Portland General Electric

- Approximately **40%** of all lighting design work are residential or commercial area light installations
- Average time from assignment to job construction of area light design jobs is approximately **3 months**
- Area light design jobs over 45 days without completed design is **over 55**
- Year to date, **10%** of all Area Light design jobs are taking over **60 days to design**
- Outdoor Lighting has taken on design of all Street and Area Light Damage Claims jobs. This is a **20% increase** over current lighting design job volume. Car hit pole replacement is a very sensitive and highly visible issue to municipalities.

Upcoming Projects 2016/2017
Major Impacts on Municipality Relationships

Portland General Electric

- McLoughlin Blvd Street Improvement Project for Clackamas County
  - One of the largest streetlight improvement projects in the history of PGE's Lighting department
  - Project will require approximately .5 FTE for 18 to 24 months
  - Clackamas County is PGE's largest Option A customer, success of this project is vital to maintain positive relationship with this important customer
- City of Portland 240V Underground Repair Project
  - Project duration is approximately 6 months to 1 year
  - Project required to bring circuit into NESC compliance, ensuring public and worker safety
  - Success of this and projects like this affect our relationship with City of Portland in all aspects (City projects, franchise agreements, ROW discussions, etc)
- Expected Future Option B to C Conversions
  - City of Salem, City of Hillsboro, Washington County (3 of our largest lighting customers)
  - LSDPM resources are presently inadequate to support the conversions and maintain positive relationships with these municipalities.
    - Locates
    - Transfers
    - Claims
    - Transition of underground circuit responsibility

Issues Impacting Customer Service Levels

Portland General Electric

Maximo and GWD Impacts on Work

- System in its current state takes more oversight throughout project lifespan
- Increased inter-departmental communication
- In its present state Maximo/GWD is more time consuming than WMS to create designs
- OLS is currently fielding all questions from T&D designers related to creating lighting designs (this is opposite of how the support was expected to flow).

Regulatory Requirements

- Municipalities require photometric designs meeting IES standards on the majority of new subdivision installations
- Street lights must be installed before developers are allowed to sell units or before residents are allowed to occupy (heightened emphasis on safety)
- T&D and Lighting Design must both be completed to meet customer needs

Improved Economy Leading to Increase in Large Residential and Commercial Developments

- Developers and municipalities requesting more varied pole and lighting fixtures resulting in additional design time
- Emerging lighting technology (LED decorative lighting) requires more standards, vendor, municipality, and developer education and management.
- Long lead time material management

Strategic Resource Proposal

Portland General Electric

Customer Service – Lighting Design Jobs

- Increase Lighting SDPM FTE count to maintain OLS to T&D ratio – increase of 1 OLS FTE

Customer Service – Lighting Damage Claims Jobs (Car Hit Poles)

- Additional FTE needed to cover 20% increase over current lighting design job volume – increase of 1 OLS FTE

Customer Service – 2016/2017 Projects

McLoughlin Blvd Street Improvement Project for Clackamas County

City of Portland 240V Underground Repair Project

Expected Future Option B to C Conversions

- Approximately .5 OLS FTE needed for 18 to 24 months

Increased FTE Count for 2016/2017 would also serve as succession planning for anticipated retirements (3 expected retirements in 18 to 34 months).
FTE count would then roll back to current level in 2018/2019.

Process and System Improvements

- Combining LOA and LEA agreements for developers
    - Reducing paperwork, coordination and time for both PGE and developer
- Improve Materials Forecasting
    - Reduce materials lead times
    - Ability to inform developer of material shortages in a timely manner
- Better coordination between Lighting Services and T&D
    - Treat each development as an overall project
- Improved scheduling process with PSLD
    - Improve Target Start/Finish date management
    - Improve process between scheduling and material arrivals
- Process improvements with T&D Avery Support and Regional Job Processors
    - Streamline traffic control plans and permit acquisition
    - Work Order task management to ensure timely job completion and billing
- Maximo Defects and work processes expected to improve and create efficiencies
- GWD coming online will allow faster turnaround times on small development and area light jobs

Conclusion and Recommendation

Portland General Electric

Conclusion:

Increased workload volume over the next 2 to 3 years is equivalent to 2.5 FTEs

Recommendation:

Increase Lighting Services FTE count by 2 for 2 to 3 years

Summary:
Lighting Services FTE count would increase by 2 for 2 to 3 years. This would also serve as succession planning for anticipated retirements (3 expected retirements in 18 to 34 months). FTE count would then roll back to current level in 2018/2019 due to improved process and system efficiencies and an increase in Option C lighting via expected FTE retirements.

Developer Complaints

Portland General Electric

Customer 1

- Customer 1's contractors need to have information to know what's expected of them. PGE doesn't provide that info. Handwritten drawings can work for them—"takes too long to get stuff designed".

Customer 2

- "Bigger problem is our Streetlight Line Extension Allowance (LEA) paperwork. Wondered why they can't get a check to PGE earlier as a "deposit", and the account reconciliations can happen later. We are both good for our money. Time lags for the paperwork to catch up are killing us."

- Street lights take 2-3 months from the time they show up to the time they are connected with power – "that's way too long". PGE issues with LED bulbs required to install. [redacted] asked that PGE get more LED bulbs in inventory, and fast.

Customer 3

- Street lights are their biggest concern. Wants PGE to work more closely with NEI (contract installer). Is it an option for PGE to shop out their streetlight construction work?

Main Functions for Lighting SDPMs

Portland General Electric

*New / Expanded Function	Annual Approved WO Count (Nov 14 - Nov 15)	% of Existing Workload
New Subdivisions	349	44%
Option A and B (Light pattern and electrical design) Municipal Lighting for Subdivisions		
Option C (Energize Only) Municipal Lighting for Subdivisions		
Support of new Option A or B LED Conversions		
Area Lights	327	41%
Area Light Installations (Residential & Commercial), increasing demand due to LED availability		
Area Light Removals (Residential & Commercial)		
Misc Jobs	112	14%
Light Shield Installations		
Option C or Field Corrections Records Only Jobs*		
Option C Lights on PGE Distribution Poles*		?
Inspecting new requests or moves to ensure compliance with NESC and PGE Standards		
Generate work order for electrical connection		
Street Light Damage Claims Jobs*	150	+19%
Outdoor Lighting has taken on design of all Streetlight Damage Claims jobs (includes streetlight only poles in addition to municipality lights on Distribution poles)		

ADDITIONAL FUNCTIONS	
Support of GWD testing, development, and training – 2015 thru ? *	Currently 25% of Aroun's time
Municipalities require photometric designs meeting IES standards on the majority of new subdivision installations *	
Developers and municipalities requesting more varied pole and lighting fixtures resulting in additional design time and long lead time material management *	
New Material specifications and review driven by technology advancements *	
Increased inquiries by municipalities, developers, and customers about LED options *	

LED State of the Union

Portland General Electric

Streetlights Installed (2013 – 2014)	**34,246**
Area Lights Installed (2014)	**10,788**
Estimated kWh Saved HPS →LED	3.24m kW
Municipal Light Poles purchased by PGE	1,305
Estimated Energy Trust Incentives Delivered	$1.35 million

Largest Municipality Conversions	Option A	Option B	Total
Clackamas County Service District	5,651	578	6,229
Washington County	3,664		3,664
Oregon City	1,103	1,613	2,716
Salem	2,594		2,594
Beaverton	2,264		2,264
Milwaukie	1,799	174	1,973
Tigard	568	1,399	1,967
Hillsboro	1,771		1,771
City of Keizer	1,241	182	1,423
Woodburn	652	567	1,219
East Salem Service District	1,094	1	1,095
West Linn	631	275	906
Silverton	506	272	778
	23,538	5,061	28,599

	B to C Commitment	**B to C Fixture Count**	**PGE Streetlight Only Poles to Sell**
CITY OF PORTLAND	**X**	**44,000**	**4,256**
CITY OF GRESHAM	**X**	**8,000**	**20**
CITY OF LAKE OSWEGO	**X**	**2,800**	**78**
MULTNOMAH COUNTY	**X**	**2,600**	**69**
CITY OF SANDY	*Near Future*	*900*	*15*
		58,300	4,438

Historic LSDPM Job Counts

Portland General Electric

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Assigned	1271	1130	1094	1148	1081	1048	1118	1236	1318	*1160*
Approved	788	831	670	663	665	595	592	738	715	*700*

- 2015 Job Counts fall within the historic average
- 2015 Q4 totals extrapolated from Jan thru Sept Average

April 6, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 367
Dated March 28, 2017

Request:

See Order No. 13-459 from PGE's UE 262.

a. Regarding maintenance of associated circuits, the Second Partial Stipulation states:

> **The costs of maintenance of associated circuits will be reassigned from distribution to the maintenance prices for Schedule 91 Option A and B, Schedule 95 Option A, and Schedule 15 prices.**

Please provide electronic, Excel workpapers showing that PGE has assigned the maintenance costs of associated circuits to the schedules as described in Order No. 13-459.

b. Regarding the calculation of Option B pole prices, Order No. 13-459 states:

> **Schedule 91 Option B pole prices will be calculated using a 0.20 percent replacement rate. The Option B pole price is calculated by multiplying the Option A pole price by the 0.2 percent replacement rate**

Please provide electronic, Excel workpapers showing that Option B pole prices have been calculated as described in Order No. 13-459. In a narrative response, please cite the cell reference of at least one example of a Schedule 91 Option B pole price calculated as described above.

Response:

a. Additional context regarding the treatment of associated streetlight circuit maintenance is included in UE 262 / Stipulating Parties / 200, page 11, lines 7-17. The Commission summarized this in Order No. 13-459, page 11, stating; "Second, maintenance costs of associated circuits will continue to be assigned directly to the maintenance prices for

Schedule 91 Option A and B, Schedule 95 Option A and Schedule 15 prices, rather than recover costs through distribution, a change PGE had proposed in its initial filing."

PGE includes maintenance of circuits for Schedule 91 Option A and B, Schedule 95 Option A, and Schedule 15 in its streetlight maintenance cost study provided in work papers for PGE Exhibit 1300. See column Z in worksheet "MC" contained in the file "2018 Stl Maintenance Cost Study.xlsx."

b. PGE also includes investment calculations for Schedule 91 Option A and B pole prices in its work papers for PGE Exhibit 1300. See column J in worksheet "91 Pole Inv" contained in the file "2018 Stl Investment Calc.xlsx." Please reference Cell J13 as an example of a Schedule 91 Option B pole price calculation.

CASE: UE 319
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1300

Opening Testimony

REDACTED

June 16, 2017

Q. Please state your name, occupation, and business address.

A. My name is Max St. Brown. I am a Senior Utility Economist employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/1301.

Q. What is the purpose of your testimony?

A. I analyze seven issues in PGE's request for a general rate revision resulting in two adjustments.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared

Exhibit Staff/1302 – St. Brown/1-3: Staff's load forecasting equations;
Exhibit Staff/1302 – St. Brown/4-10: Staff's load forecasting figures.
Exhibit Staff/1303 – St. Brown/1-3: Staff's confidential low services connection correction Exhibits;
Exhibit Staff/1303 – St. Brown/4-6: Staff's confidential temporary service Exhibits.
Exhibit Staff/1304 – St. Brown/1-4: reference materials related to load forecasting;
Exhibit Staff/1304 – St. Brown/5-10: reference materials related to rate design;
Exhibit Staff/1304 – St. Brown/11-13: reference materials related to temporary service.
Exhibit Staff/1305 – St. Brown/1-16: PGE Responses to Staff DR Nos. 322, 331, 329, 321, 322, 348, 396, 532, 638, 637, 639, 538, 539, 434, 439, and a workpaper from PGE's Exhibit 1200.

Q. How is your testimony organized?

A. My testimony is organized as follows:

<u>ISSUE 1: LOW SERVICES CONNECTION CORRECTION</u>

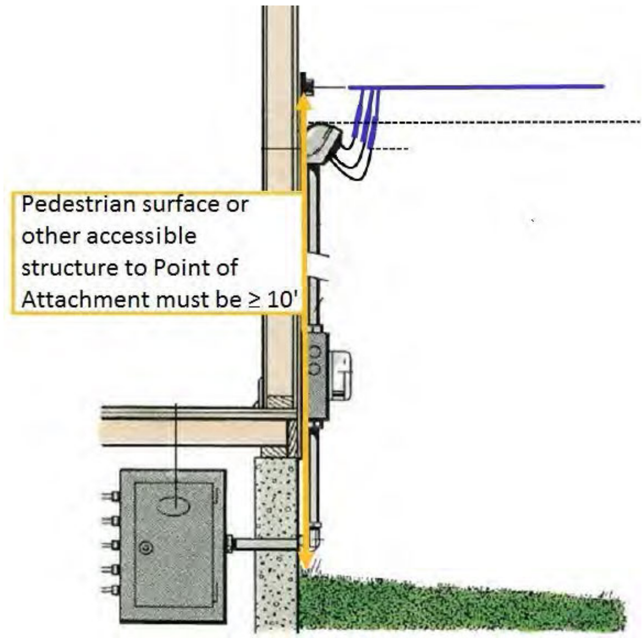
Q. Please summarize Staff's low services connection correction adjustment.

A. Staff recommends a downward adjustment to Test Year expense of $1,076,945 and a downward adjustment to FTEs of 1.36. Staff witness Marianne Gardner is calculating the amount in wages and salaries in her Exhibit Staff/400 testimony.

Q. Please describe the low services connection correction issue.

A. Oregon electric utilities have encountered service connections that do not meet National Electric Safety Code (NESC) requirements for minimum height. Per the NESC, Oregon PUC Safety, Reliability, and Security Division Staff direct each electric utility to correct the low service connections in their respective service territories as they are identified. The diagram below shows an example point of connection and states that the point of attachment should be at least 10 feet above surface level:[1]

[1] This is a simplified version of the diagram provided by PGE in its response to Staff DR No. 322. Page 2 of Attachment F to PGE's response to Staff DR No. 322 is found at Staff Exhibit 1305/1.



Q. Are low services connections a safety hazard?

A. Yes, and accordingly, PGE corrects low service connections in connection with its Facility Inspections and Treatment to the National Electric Safety Code (FITNES) program.

Q. How many low service connections are in PGE's service territory?

A. This value is unknown as it would require an inspection of all points of service. However, PGE estimates that there are 32,000 violations by extrapolating the violations found during recent inspections.[2]

Q. Please describe PGE's 2015 low services pilot.

A. PGE re-inspected 10 percent of the low services identified in 2015 and kept data about the characteristics of those services and the type of correction work required. PGE found that 83.6 percent of corrections could be corrected by installing guarding material on PGE-owned equipment. The remaining 16.4

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[2] See PGE/802, Nicholson – Bekkedahl/2.

percent of corrections required work to customer-owned equipment and accounted for 76 percent of costs. The table below provides 2015 FITNES height data:

	PGE-owned equipment	Customer-owned equipment
8-10ft 2015 FITNES height	200	31
< 8ft 2015 FITNES height	39	18

Note that in the table above, summing the customer-owned equipment (31+18) and dividing by the total services (200+39+31+18) does not equal 16.4 percent; this is because height data is missing for 11 percent of services.[3]

Q. Why are low services connection corrections a rate case issue?

A. Primarily because some low service connection corrections require work on customer-owned equipment, which PGE contends is an expense not already included in base rates.

Q. Does Staff agree that some low service connection corrections will require work on customer-owned equipment?

A. Yes.

Q. Does Staff agree that PGE should receive full recovery for expenses associated with correcting low service connections?

A. No, given that low service connection NESC violations were and are an avoidable problem, Staff believes that assigning all of the costs of correction onto customers without violations is not equitable.

[3] Staff/1305, St. Brown/2, PGE's response to Staff DR 331, provided as a digital file.

Q. Can you provide examples of how low service connection NESC violations were an avoidable problem?

A. Yes, please see Confidential Staff Exhibit 1303/1-3 for photos of NESC violations in Portland, Oregon City, and St. Paul. To Staff's best judgment, it appears that in each case the NESC violation could have been avoided by PGE refusing to connect the service.

Q. Can PGE refuse to connect low services?

A. Yes, in fact, PGE's own service requirements provide guidelines that Staff interprets to recommend not doing the service connections shown in Confidential Staff Exhibit 1303/1-3. PGE agrees the service connections are illegal in its response to Staff DR No. 329 by stating "there has been no electric service requirement standard that has allowed a height below 8 feet [from a pedestrian surface]."[4]

Q. How is PGE proposing to operate its low services connection correction program?

A. PGE's FITNES program identifies service connections below 10 feet in order to comply with NESC. PGE proposes that "if the point of attachment and/or the customer-owned weather head on a building that was constructed prior to 1977 has less than 8' vertical clearance and raising the point of attachment cannot be addressed by modifications to PGE-owned equipment alone …, then PGE's Low Clearance Program will work with the customer and their licensed electrical contractor to make the repair."[5]

[4] PGE's response to Staff DR 329 is attached as Staff Exhibit 1305/3.
[5] See Staff/1305 St. Brown/4, PGE's response to Staff DR 321.

Q. Why does PGE reference 1977 and connections below 8 feet?

A. NESC has never allowed service connections below 8 feet. In very limited circumstances, service drops below 10 feet, but above 8 feet, were allowed prior to 1977, but only after 1961.[6]

Q. What costs associated with correcting low service connections are PGE requesting to include in its proposed rates?

A. PGE includes costs for two new FTEs associated with correcting low service clearances.[7] PGE's Exhibit 800 "*T&D O&M.xlsx*" workpaper increases test year expenses by $1,583,742 for customer-side repair of low service clearances.

Q. Why is PGE not proposing to collect expenses related to repair of customer-owned equipment directly from those customers?

A. Presumably, the Company agrees that the quickest solution to this safety hazard is to assist home or business owners with replacement of any equipment necessary to comply with NESC. Staff believes that billing or shutting off service to customers served by utility point of connections in violation of NESC would not be a rapid solution to this safety hazard.

Q. Would Staff oppose collecting expenses related to repair of customer-owned equipment directly from those customers for any other reasons?

A. Yes, as described above, the Company should never have connected many of its point of attachments currently in violation of NESC to begin with. The home

[6] See Staff/1305, St. Brown/5, OPUC's figure provided on page 5 of Attachment E to PGE's response to Staff DR 322.
[7] PGE/802, Nicholson – Bekkedahl/2-3.

or business owner is not the subject matter expert, and it seems unreasonable to hold the home or business owner accountable for the probable oversight of the electrician, electrical inspector, or utility employee.

Q. What is Staff's recommended adjustment related to correcting low service connections?

A. Staff recommends that expenses and FTEs associated with correcting low service connections be adjusted downwards by 68 percent. First, Staff recommends disallowance of PGE's request to recover costs associated with correcting low service connections below 8 feet (36.7 percent).[8] Second, Staff recommends a 50-50 cost sharing for corrections to service connections between 8 and 10 feet (31.6 percent).[9]

Multiplying the Company's request by 68 percent provides Staff's recommendation to adjust test year expenses downwards by $1,076,945 and adjust FTEs downwards by 1.36.

Q. Why does Staff recommend a disallowance of PGE's request to recover costs for corrections to service connections below 8 feet?

A. Staff recommends a disallowance of PGE's requested costs for service connections below 8 feet because connections below that height have never been permitted under the current and previous versions of the NESC.

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[8] Per PGE's response to Staff DR 331, 49 of the 56 violations requiring work on customer-side equipment from the Company's 2015 Low Services Pilot have 2015 FITNES height data. 18 of those 49 violations (36.7 percent) are below 8ft.

[9] Ibid. Where ½ * 31 ÷ 49 = 31.6 percent.

Q. Why does Staff recommend a 50-50 cost sharing for corrections to service connections between 8 and 10 feet?

A. Staff considered recommending disallowance of all of PGE's proposed expenses associated with low service connection corrections, however, that is not Staff's recommendation at this time. The 50-50 cost sharing of 8 to 10 feet service connections recommended by Staff enables a prompt and cooperative solution to this safety hazard.

Importantly, some of the violations identified in PGE's 2015 Low Services Pilot do not have height data. For this reason, Staff recommends that the actual costs of correcting low services connections, requiring work on customer-side equipment, be looked at again in PGE's next rate case at a future date.

ISSUE 2: NON-RESIDENTIAL LOAD FORECAST

Q. Please summarize Staff's non-residential load forecast adjustment.

A. Staff recommends a downward adjustment to Test Year revenue of $6,257,712. However, the Company will update its forecast with new data later in this proceeding. Thus, the proposed dollar adjustment is illustrative at this point.

Q. How often does the Company update its load forecast?

A. In this docket the Company will update its forecast at least one more time around October, 2017 and will file updated power cost, revenue projections, and the resulting revenue requirements. Staff has limited ability at that point to contest the Company's projections. It would be preferable, if Staff and the Company or other parties have alternative modeling recommendations, that the Company be directed by the Commission as to how to develop its final forecast to the extent these issues are not resolved among the parties.

Q. How does the Company use its load forecast?

A. Within the rate case, the Company uses its load forecast to compute expected revenue, which informs the level of rates required to recover its revenue requirement. The Company's load forecast is replicated below from PGE/1402, Cody – Macfarlane/1, except that Staff has combined primary, secondary, and transmission loads within each schedule:

Rate Schedule	Number of Customers	MWH Sales
7	772,009	7,559,949
15	-	16,416
32	92,495	1,561,634
38	384	30,166
47	3,015	21,388
49	1,320	65,471
83	11,418	2,790,676
85	1,432	2,880,538
89	17	637,306
90-P	4	1,589,508
91/95	203	50,700
92	17	2,907
485	255	853,496
489	16	1,064,309

All else equal, an increase in any of the billing determinants in the table above lowers PGE's necessary rate increase.

Q. Does the Company describe its load forecast as a primary element of its filing?

A. Yes, PGE is requesting about $25 million in increased revenues to offset its lower load forecast relative to its forecast used to set prices in 2016.[10]

Q. What is the main driver of PGE's lower load forecast?

A. The Company uses a trended weather approach. A trended weather approach departs from the practices of all other Oregon investor-owned utilities (IOUs) by assuming that normal weather is not an average of past historical weather.

[10] PGE/100, Piro – Lobdell/5, lines 9-12.

Furthermore, PGE is unaware of any state Commission ever adopting a trended weather approach.[11]

Q. Does Staff support PGE's trended weather approach?

A. No, as is described in Staff witness Lance Kaufman's testimony in Exhibit Staff/700.

Q. Please describe the Company's non-residential forecasts.

A. The Company forecasts the load of its largest manufacturing customers using customer and plant specific information gathered by PGE employees who regularly communicate with PGE's large customers.[12] The Company forecasts all other commercial and manufacturing loads using regression models. Specifically, loads are grouped by similar business types as defined by their North American Industry Classification System (NAICS) code. Then, the Company uses a NAICS to rate schedule conversion.[13]

Q. How does Staff propose to adjust the Company's forecast?

A. The Company is using models very similar to its integrated resource plan (IRP) load forecasting models. In that proceeding, Staff expressed concern that PGE's models are unlikely to perform well in the presence of non-stationary variables.[14] In that proceeding, PGE indicated that it has begun to re-evaluate its economic drivers. However, because the Company has not yet alleviated

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[11] See Staff/1305, St. Brown/6, PGE's response to Staff DR No. 348.
[12] See Staff/1305, St. Brown/7, PGE's Exhibit 1200 workpaper "1 Model Structure.pdf".
[13] Ibid.
[14] See e.g., LC 66 Staff Final Comments (May 12, 2017), p. 27. Briefly, "If the characteristics of the stochastic process change over time, i.e., if the process is *nonstationary*, it will often be difficult to represent the time series over past and future intervals of time by a simple algebraic model." Pindyck, Robert S. and Daniel L. Rubinfeld, "Econometric Models and Economic Forecasts," Fourth Edition, Irwin/McGraw-Hill, page 493, 1998.

its problems due to non-stationary variables, Staff re-forecasted each of the Company's non-residential models for this GRC. Due to time constraints, Staff focused on five main improvements. Staff believes that this is an important first step and looks forward to working with PGE to continue to improve PGE's forecasting methodology in future proceedings.

Q. Please state Staff's five main improvements.

A. The Staff improved the Company's forecasts with the following five improvements to the Company's modeling:

1. Non-stationarity is addressed by using an integrated model that can difference the data.
2. Models are developed using a consistent time period of data;
3. Each commercial model includes weather variables;
4. Each model includes a variable for Energy Trust EE funding; and
5. Model parameters are selected using an automated computer algorithm that minimizes each model's information loss.

Q. Did Staff make any other adjustments when reforecasting the Company's loads?

A. Yes, Staff made three other minor changes. First, because the Company did not provide a forecast for its number of residential accounts (variable NSC7) in its workpapers or in response to Staff DR No. 578, Staff dropped that variable from the model. Staff agrees with the Company that number of residential accounts is probably a good forecast driver of the energy use of restaurants and can update that model in rebuttal testimony. Second, Staff eliminated intervention variables unless there was a clear data error (such as a negative value for load). Third, the Oregon Office of Economic Analysis produced an updated employment forecast on May 16, 2017, so Staff used that forecast directly, rather than the Company's workpaper copy of a prior forecast.

Q. Please support Improvement 1: Non-stationarity is addressed by using an integrated model that can difference the data.

A. Failure to remove trends could result in spurious regressions - as was described in Staff's LC 66 comments.[15]

Q. Please support Improvement 2: Models are developed using a consistent time period of data.

A. The Company's regression models start from various time periods with no accompanying explanation from the Company. For example, models start in January 2000, August 2003, January 2004, March 2004, or February 2008. In prior proceedings, Staff has recommended against restricted sample sizes.[16] Because data related to the Energy Trust of Oregon is only readily available from 2004, Staff started all forecasting models in January 2004.

Q. Please support Improvement 3: Each commercial model includes weather variables.

A. The Company uses monthly dummy variables to control for non-weather monthly load drivers. The Minitab Blog describes the importance of control variables by describing that multiple regression models (which PGE uses)

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[15] Ibid.
[16] See Staff Testimony in Support of the Stipulation Resolving All Issues in Avista's UG 284 GRC at 29. January 29, 2015.

allow researchers to "isolate the role of one variable from all of the others in the model" by including all important variables in the model. And "not including an important variable (leaving it uncontrolled) can completely mess up your results."[17]

Based on the above description of control variables, Staff is surprised that the Company opts not to control for weather in each of its commercial schedules. For example, when forecasting the load of restaurants, hotels, or government buildings the Company controls for the impact of both warm and cool weather. However, in its forecast of merchandise stores, the Company only includes the impact of warm weather as a forecast driver. In this context, Staff believes it is more reasonable to also include HDD (heating degree days) to control for potential cold weather effects on the load of merchandise stores. Thus Staff recommends that the Company include HDD (heating degree days) and CDD in each of its commercial forecasts. Granted, the coefficients on these variables might not be significant in some regressions, but Staff believes that at a minimum, their inclusion in the models will serve as important control variables.

Q. Please support Measure 4: Each model includes a variable for Energy Trust EE funding.

A. Staff described PGE's approach to adjust for incremental SB 838 measures using out of model adjustments in Docket No. UE 283:

[17] Staff/1304, St. Brown/1-3, Jim Frost, "A Tribute to Regression Analysis," *The Minitab Blog*, May 17, 2012. Available at: http://blog.minitab.com/blog/adventures-in-statistics-2/a-tribute-to-regression-analysis.

> *[PGE's] energy efficiency adjustment forecast modifies the forecast to account for new energy efficiency measures. This adjustment only accounts for energy efficiency measures related to SB 838. The Energy Trust of Oregon's (ETO) forecast for 2014 and 2015 energy efficiency measures is shaped into monthly incremental savings. The monthly incremental savings are than aggregated into monthly cumulative energy savings. These savings are then allocated to each forecast group based on a historic pattern. The forecast group's cumulative energy efficiency savings are removed from the group's price adjusted forecast.*[18]

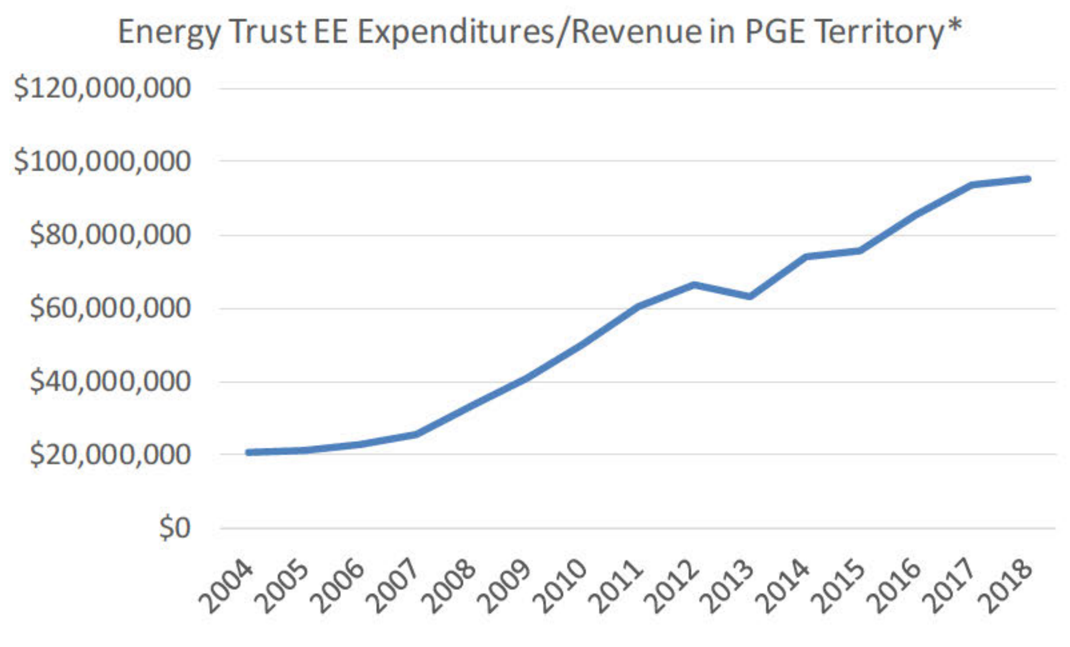
Staff noted its concern with distinguishing between EE funded through SB 1149 and that funded through SB 838 and the consequence that energy use was forecasted by customer group rather than customer class. Staff noted it did not have a solution to its concern at that time, but that it was exploring solutions.[19]

In a response to a Staff data request provided in this case, PGE states "PGE is aware of several alternative methods to account for energy efficiency savings directly in regression-based forecast models being used in electric utility deliveries forecasting," and "PGE has not found … reasonable historical series to include in regression analysis, [and] PGE has been unable to move forward with modeling investigation of alternative methods."[20]

Therefore, in good faith, Staff makes this first-pass approach at modeling EE savings directly in regression-based forecast models. Admittedly, EE expenditures by rate schedule would be a better variable than total EE expenditures/revenues in PGE's service territory. However, schedule-specific-data was not easy to obtain, so Staff used EE expenditures at the system level

[18] UE 283 Staff/300, Kaufman/15, lines 3-11.
[19] UE 283 Staff/300, Kaufman/15-16.
[20] Staff/1305, St. Brown/8, PGE's response to Staff DR No. 396.

and encourages PGE to continue its work to find a better variable. The graph below depicts the trend of summed SB 1149 and SB 838 expenditures/ revenue in PGE territory:



**2004 to 2009 data are revenues, 2010 to 2016 data are expenditures, 2017 to 2018 data are projected expenditures from ETO's approved 2017 budget*

Notably, in the graph above there are over 10 years of post-2007 data when both SB 1149 and SB 838 were in place. Thus, the Company's differentiation between SB 1149 and SB 838 is not clear to Staff.

Q. Please describe how Staff's incremental EE variable performed in Staff's regression models.

A. In most of Staff's regressions, the Energy Trust EE expenditures variable is small and statistically insignificant. This is evidence that historic data already reflects the trend of Energy Trust EE expenditures and that an out-of-model incremental adjustment is not needed. This is also evidence that the variable related to Energy Trust EE funding could be dropped with little predictive power lost in the model. Staff notes that in Avista's most recent GRC, Docket No. UE 235, Avista assumed that historic data already accounted for EE measures and did not include an EE variable in the regression or make an out-of-model adjustment.

Q. Please support Improvement 5: Model parameters are selected using an automated computer algorithm that minimizes each model's information loss.

A. This is an especially important improvement because about half of the Company's models do not use any economic forecast drivers. Staff's approach is described in testimony submitted in the Avista's GRC Docket No. UG 325: "Staff produced independent forecasts using the computer assisted automatic method-selection algorithm software function "auto.arima" designed by Rob Hyndman, the editor-in-chief of the International Journal of Forecasting. The software function automatically selects the most accurate model parameters."[21] Staff also used this approach in the Cascade's GRC docketed as Docket No. UG 305.

In addition to maximizing the model fit, the auto.arima function has the added benefit that it is easily reproducible on the Company's or any stakeholder's personal computer using the freely available R software and the "forecast" package. Staff's models are defined in Staff/1302, St. Brown/1-3. Staff's forecasts are visually presented in Staff/1302, St. Brown/4-10.

[21] UG 325 Staff/600, St. Brown/15, lines 14-19.

Q. Did Staff experiment with any other approaches that did not lead to adjustments?

A. Yes, because commercial load was correlated with economic performance in UG 325, Staff tested whether commercial new building permits in Portland were a reliable forecast driver of the number of commercial customers. However, that data series did not appear to be a reliable forecast driver.

Q. Please summarize Staff's adjustment to load.

A. The table below presents Staff's load forecast versus the Company's load forecast:

Commercial Group MWH Annual Sales				Manufacturing Group MWH Annual Sales		
	Company	Staff			Company	Staff
Food Stores	419,300	436,399				
Government and Education	960,500	953,878				
Health	726,000	739,552		Food	264,100	263,485
Lodging	102,500	107,479		High Tech	2,614,100	111,915
Misc. Commercial	632,300	647,999		Lumber	96,500	54,913
Merchandise Stores	352,900	350,366		Metals	426,200	185,214
Office and F.I.R.E.	957,300	1,033,769		Other Manufacturing	728,900	632,558
Other Services	854,600	871,863		Paper	291,600	46,157
Other Trade	703,200	704,596		Trans Equip	167,200	55,575
Restaurants	485,900	501,800		Large Manufacturing	Company	
Trans, Comm, Util	624,600	623,299			N/A	3,169,916
TOTAL	6,819,100	6,971,001			4,588,600	4,519,733
Percent difference		**2.23%**				**-1.50%**

In the table above, Staff forecasts 83,033 additional MWH sales beyond the Company's forecast. Staff forecasts lower manufacturing sales than the Company. Staff's forecast is consistent its concern in LC 66 that "PGE's projected growth rates for its industrial customers unreasonably exceed recent trends."[22]

Q. Please summarize Staff's non-residential load forecasting revenue adjustment.

A. For simplicity, Staff assumed that increases in load would be distributed among rate schedules and billing determinants in an equivalent manner to the Company's assumptions. This assumption also makes sense because the Company's non-residential load forecasts do not differentiate between new load from new customers versus new load from increased use-per-customer among existing customers. Under this assumption, Staff multiplied the Company's revenue from the commercial group by Staff's load increase of 2.23 percent to obtain an $11,774,503 revenue increase and multiplied the Company's revenue from the manufacturing group by Staff's load decrease of 1.50 percent to obtain a $5,516,791 revenue decrease. Together, Staff forecasts that the Company's proposed rates would bring in $6,257,712 ($11,774,503 - $5,516,791) beyond the Company's revenue forecast, and thus the Company's revenue requirement should be adjusted downwards accordingly.

Staff notes that the shortcoming of this simplifying assumption is that all billing determinants are assumed to have a one-to-one percentage relationship with load. In reality, while peak demand is correlated with energy usage, it is not a one-to-one relationship. Staff is open to working with the Company to

[22] LC 66 Staff's Initial Comments (January 24, 2017).
http://edocs.puc.state.or.us/efdocs/HAC/lc66hac133439.pdf

make Staff's conversion from the load forecast to the revenue forecast more precise.

Q. Does Staff make any big-picture recommendations?

A. Yes, given that the Company's models differ significantly from other Oregon IOUs (for example, other IOUs do not aggregate by NAICS code) Staff believes that stakeholders would benefit from data on the relative performance of different models. Staff recommends that the Company increase its practice of trying different load forecasting approaches and later comparing forecasts to actuals in order to gain insight into which models work best. That is standard practice in many industries, for example, describing its home price estimation algorithm, Zillow states, "since Zillow's inception …, we have deployed three completely new versions of the algorithm … and … incremental improvements are made between major upgrades with new iterations being deployed regularly."[23]

Q. Please discuss the process you envision given that PGE will be revising its load forecast during the year and how Staff could have its adjustments incorporated.

A. PGE requests that "the Commission: 1) accept as a preliminary matter [its] forecast of energy deliveries … and 2) set a schedule in this proceeding allowing for periodic updates of the energy delivery forecast for 2018." Due to Staff's recommended modeling changes described above, Staff recommends that PGE's forecast is rejected as a preliminary matter. There is a trade off in

[23] Staff/1304, St. Brown/4, Zillow.com, "Does the Zestimate algorithm ever change?" Accessed May 31, 2017. Available at: https://www.zillow.com/zestimate/#faq-6

updated forecasts. On the one hand, more recent weather and economic data will allow more accurate forecasts, but on the other hand, Staff will not have adequate time to vet the Company's models if they are prepared too close to the rate effective date. Thus, Staff recommends allowing PGE to update its forecast using Staff's recommended methodology, while accepting Staff's forecasts as a preliminary matter if an updated forecast cannot be agreed on by all parties.

ISSUE 3: LEGAL EXPENSES FOR PGE'S CHALLENGE OF CITY OF GRESHAM'S RESOLUTION 3056

Q. Please describe the issue.

A. Docket No. UE 324 provides the legal briefs related to PGE’s request to recover retroactively approximately $7 million dollars in privilege tax payments from City of Gresham customers due to PGE not collecting these dollars while PGE and the City of Gresham litigated the issue.

Q. Please describe Staff’s recommendation.

A. Staff issued DRs 642-643, with responses due June 14, 2017, asking PGE if it included the litigation costs of the issue in this rate case. If “yes,” Staff recommends that those costs be disallowed because PGE has not demonstrated that its legal challenge was for the benefit of customers. Staff will continue to investigate this issue and can report back in Rebuttal Testimony.

<u>ISSUE 4: CUSTOMER AND DISTRIBUTION MARGINAL COST OF SERVICE, IMPACTS ON RATE DESIGN</u>

Q. Please summarize Staff's rate design adjustments related to PGE's Marginal Cost of Service study.

A. Staff recommends four adjustments. First, Staff recommends that PGE include cost savings due to off-peak usage for residential time of use (TOU) customers. Second, Staff recommends that PGE increase its residential fixed charge by $0.50 rather than $1. Third, Staff recommends that PGE eliminate its Schedule 38 or increase those rates. Fourth, Staff recommends that PGE eliminate its customer impact offsets (CIO) in this GRC.

Q. Please describe PGE's Marginal Cost of Service study.

A. PGE testifies that its marginal cost study "compute[s] the cost of rebuilding the [distribution equipment] in today's dollars."[24] The purpose being that book values do not have a comparable basis of depreciation – thus book values would not clearly indicate which schedules are more costly to serve. PGE then allocates the rebuilding cost among customers and uses those allocation percentages to spread the rates (which are designed to recover book values).

PGE computes the rebuilding cost of five components separately. For each component PGE identifies a cost driver and then allocates based on that driver.

[24] PGE/1300, Cody – Macfarlane/9-10, lines 2-3.

Q. Please describe the purpose of PGE's Marginal Cost of Service study.

A. The purpose of PGE's Marginal Cost of Service study is to allocate its revenue requirement equitably; the marginal cost study informs PGE's rate design. PGE offers 14 rate schedules in an effort to match customer and load characteristics to billing determinants (per customer charges, per kWh rates, per kW rates, facilities charges).[25] Customers with demand below 200 kW may select between schedules based on whether they desire a time-of-use (TOU) energy charge.

OAR 860-038-0200 directs the Company to unbundle the costs by functions: generation, transmission, distribution, ancillary services, and consumer services (billing, metering, other). This allows direct access customers to pay for only what they use.

Q. PGE had a recent rate case, Docket No. UE 294. Did parties agree to any Marginal Cost of Service study improvements in that proceeding?

A. Yes, Order No. 15-356 (UE 294) at 11 states, "the parties agree that [evaluating the costs of maintaining secondary conductors and how that maintenance cost should be allocated] should be part of PGE's next general rate case and that the evaluation will improve the company's marginal cost estimates and provide for an improved allocation of costs to the rate schedules and delivery voltages."

[25] The marginal cost study includes 13 schedules because PGE does not separate residential Schedule 6 from Schedule 7.

Q. Did PGE perform this analysis?

A. Yes, PGE evaluated maintenance costs of secondary voltage conductors and included those costs for residential customers in its Marginal Cost of Service study.

Q. Please summarize the results of PGE's Marginal Cost of Service study.

A. PGE provides the rebuilding costs necessary to serve a customer on each schedule on PGE/1301, Cody – Macfarlane/3. To be consistent with other Oregon IOUs, Staff used the Company's workpaper to compute relative revenue-to-marginal cost ratios. Relative revenue-to-marginal cost is a popular metric (for example used in Avista's UG 325 rate case and Cascade's UG 305 rate case) and can be computed from PGE's Exhibit 1403. The relative revenue-to-cost ratio is presented in the second column of the figure below along with PGE's recommended rate increases in the third column, as found in page 1 of Exhibit 1402.[26]

Rate Schedule	Revenue-to-Cost at Present Rates	Estimated Increase in Base Rates from PGE's Rate Spread
Schedule 7, Residential	0.98	7.1%
Schedule 15, Outdoor lighting	1.05	2.0%
Schedule 32, <30 kW	1.00	5.7%
Schedule 38, <200 kW TOU	0.98	8.1%
Schedule 47, Small irrigation	1.01	4.8%
Schedule 49, Large irrigation	0.97	9.1%
Schedule 83, 31-200 kW	1.01	4.2%
Schedule 85, 201 kW to 4 MW	1.02	3.7%
Schedule 89, >4 MW	1.05	1.2%
Schedule 90, >4 MW and <100 MWa	1.04	1.2%
Schedules 91 & 95, Street highway lighting	1.03	2.1%
Schedule 92, Traffic signals	1.01	4.5%
Total All Schedules	1.00	5.6%

[26] Where Staff computed total Schedule instead of separating out primary and subtransmission voltages.

The table above uses Excel's conditional formatting feature to highlight schedules with revenue below cost in column 2 and to highlight schedules with the greatest proposed rate increases in column 3. The alignment of highlighting indicates that the Company's proposal will bring revenue closer to cost of service.

Q. Does Staff believe that refinements to the Company's Marginal Cost of Service study and rate design are warranted?

A. Yes, despite the fact that the Company and Staff have worked cooperatively together on recent Marginal Cost of Service studies,[27] Staff recommends four refinements to PGE's computations.

Q. Please support Staff's first recommendation that PGE include cost savings due to off-peak usage for residential time of use (TOU) customers.

A. Residential customers are a heterogeneous group, with the average customer contributing 2.6 kW to non-coincident peak (per PGE's Exhibit 1400 workpapers) and some customers having peak demands in excess of 30 kW (per PGE's response to Staff DR 532).[28] Staff recommends that residential customers' contribution to on-peak capacity costs should not be recovered through off-peak energy charges for the residential time-of-use schedule customers. This difficulty arises because residential customers do not explicitly pay for on-peak capacity costs. Staff's proposal is described in Staff witness

[27] See for example, UE 294 Staff/300, Compton/2 "over the years [PGE's] practices relating to [its Marginal Cost of Service study] have evolved in a mutually acceptable manner—being influenced by various parties, including Staff."
[28] Staff/1305, St. Brown/9, PGE response to Staff DR No. 532.

George Compton's Exhibit 1400 opening testimony and relates to optional time-of-use residential rates.

Q. Please support Staff's second recommendation that PGE increase its residential fixed charge by $0.50 rather than $1.

A. PGE proposes to increase its residential fixed charge from $10.50 to $11.50. The Company makes this proposal "in order to better match prices to embedded costs."[29] In PGE's UE 283 GRC, Staff authored "A Short Treatise on Basic Charges." In that testimony, Staff opposed the Company's full requested increase in the fixed charge because "increasing the basic charge by 22% in the context of a general rate case involving less than 5% overall increase certainly stretches things from a customer acceptance/credibility point of view."[30] In this GRC, PGE is requesting to increase the residential fixed charge by 9.5 percent. Instead of the Company's requested residential fixed charge of $11.50, Staff recommends $11, which is a 4.8 percent increase to the current fixed charge.

Q. Please support Staff's third recommendation that PGE eliminate its Schedule 38 or increase those rates.

A. The Company uses demand meters for its customers on Schedule 83 and proposes to charge them $2.84 per kW of on-peak demand. This is an equitable approach because the customers who use the most capacity will pay the greatest capacity-related charges. Rates designed so that the cost-causer pays serve an additional benefit in that customers internalize the costs they

[29] See Lines 9-10 of PGE/1400, Cody – Macfarlane/12.
[30] See lines 20-22 of Staff/700, Compton/11 in the UE 283 GRC.

impose on the system from their own energy decisions. For example, in many jurisdictions, customers might invest in on-site battery storage for the purpose of decreasing their peak load and associated demand charges. Conversely, PGE's optional Schedule 38 does not include a demand charge and thus can allow cost shifting between customers and inefficient overuse of peak capacity. For these two reasons, Staff recommends that the Company eliminate or increase its Schedule 38 rates.

Q. Has the Company quantified the cost shifting due to Schedule 38?

A. Yes, lines 18-20 of UE 319/1400, Cody – Macfarlane/14 indicate that the Company is proposing to shift $69,000 in revenue shortfall from its 384 Schedule 38 customers onto its Schedule 32 customers. That is an annual cost of $179.69 per Schedule 38 customer.

Q. Why are current Schedule 38 rates inefficient?

A. By the Company's own admission, there is a clear incentive for customers with low load factors to self-select into Schedule 38. See the Company's response to Staff DR 638, which states, "Schedule 38 do not have demand charges due to their special characteristics (e. g., unmetered load, seasonal consumption, low load factors)."[31] As an example, a customer that uses 200 kW once in a month (such as a large electric vehicle DC fast charger) for a two-hour duration would pay just $0.38 per kW on its monthly bill. Comparatively, a similar sized customer in Pacific Power's Oregon territory would pay demand charges of

[31] Staff/1305, St. Brown/10, PGE's response to Staff DR 638.

$3.88 or $4.70 per kW and demand charges for some of California's IOUs have exceeded $20 per kW.[32]

Presumably, Pacific Power and California's IOUs use demand charges for customers with loads in excess of 30 kW for the purpose of discouraging inefficient overconsumption of capacity on a system-wide basis. PGE also admits to this in its response to Staff DR No. 637 by stating, "on-peak demand charges could encourage reductions in peak demand for individual customers depending on the nature of the customer's consumption patterns and how the demand charge is structured. PGE believes that peak demand reductions can also be accomplished through critical peak pricing, peak time rebates, and time-of-use pricing."[33] Staff recommends that PGE include demand charges, critical peak pricing, or peak time rebates in its Schedule 38. At this time, because PGE has not included any of those features in its Schedule 38, Staff recommends that PGE eliminate its Schedule 38.

Q. Please support Staff's fourth recommendation that PGE eliminate its customer impact offsets (CIO) in this rate case.

A. Staff has gone along with CIOs in past rate cases. For example, in Avista's rate case Docket No. UG 325, Staff recommended "a percentage increase that is twice that of the overall increase" for Schedule 420 commercial customers for the purpose of avoiding large rate increases for that Schedule.[34] Staff generally

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[32] Staff/1304, St. Brown/5-6, Jeffery Wishart, "Utility demand charges and electric vehicle supply equipment," *Charged Electric Vehicles Magazine*, October 31, 2013. Available at: https://chargedevs.com/features/utility-demand-charges-and-electric-vehicle-supply-equipment/
[33] Staff/1305, St. Brown/11, PGE's response to Staff DR 637.
[34] See line 21 of Staff/1100, Gibbens/11 in UG 325.

supports CIOs under the ratemaking principal of gradualism. In Docket No. UG 221, a NW Natural rate case, Staff observed, "“gradualism” (i.e., minimizing “rate shock” by not precipitously moving rates closer to costs) is a well-established pricing criterion.”[35] However, in both of those GRCs, relative revenue-to-marginal cost ratios departed significantly from unity. In the case at hand, relative revenue-to-cost ratios are near unity for all rate schedules. This has led the Company to recommend just a 1.6 percentage point higher rate increase, above the average for all schedules receiving a rate increase, for its schedule receiving the largest increase.[36] When rate adjustments are this similar, Staff sees no need to use a CIO to prevent potential rate shock.

Q. Please provide Staff’s recommended rate spread.

A. The Table Below provides Staff’s recommended rate spread versus the Company’s proposed rate spread:

Rate Schedule	Company Revenue-to-Cost at Proposed Rates	Estimated Increase in Base Rates from PGE's Rate Spread	Staff Revenue-to-Cost at Proposed Rates	Estimated Increase in Base Rates from Staff's Rate Spread
Schedule 7, Residential	0.998	7.1%	1.000	7.3%
Schedule 15, Outdoor lighting	1.013	2.0%	1.000	0.6%
Schedule 32, <30 kW	1.000	5.7%		5.7%
Schedule 38, <200 kW TOU	1.000	8.1%		N/A, discontinue
Schedule 47, Small irrigation	1.000	4.8%		4.8%
Schedule 49, Large irrigation	1.000	9.1%		9.1%
Schedule 83, 31-200 kW	1.000	4.2%		4.2%
Schedule 85, 201 kW to 4 MW	1.000	3.7%		3.5%
Schedule 89, >4 MW	1.035	1.2%	1.000	0.9%
Schedule 90, >4 MW and <100 MWa	1.000	1.2%		1.2%
Schedules 91 & 95, Street highway lighting	0.996	2.1%	1.000	2.6%
Schedule 92, Traffic signals	1.000	4.5%		4.5%
Total All Schedules	1.000	5.6%		5.6%

[35] UG 221 Staff/1500, Compton/11, lines 6-8.
[36] Where 9.1 – (7.1 + 5.7 + 8.1 + 9.1)/4 = 1.6.

As seen in the highlighted rows above, Staff's proposal results in slightly higher rates for residential customers and slightly lower rates for PGE's largest customers.

Q. Are there any other advantages to removing the CIO offsets?

A. Yes, PGE testifies that in the Company's rate spread proposal direct access Schedule 489 customers subsidize residential customers.[37] Staff believes it is appropriate for direct access customers to subsidize or be subsidized from the other cost of service customers.

Q. Does Staff have any other recommendations related to PGE's Marginal Cost of Service study and rate design proposal?

A. Yes, Staff recommends that the Company explore additional dynamic pricing options following the implementation of its Customer Engagement Transformation in 2018.

Q. Please support this recommendation.

A. PGE's residential rate design has been relatively similar since January 1, 2011, consisting of a fixed customer charge and an increasing block rate with segments below and above 1,000 kWh per month. The Company's opt-in residential time of use (TOU) rate has been relatively similar since its inception in August 1, 2001, with on-peak energy rates about three times higher than off-peak rates.

The rate design of IOUs in Washington and California differ significantly from Oregon. For example, San Diego Gas and Electric uses a minimum

[37] PGE/1400, Cody – Macfarlane/25.

charge instead of a residential fixed charge.[38] For example, Puget Sound Energy uses an increasing block rate with segments below and above 600 kWh instead of 1,000 kWh.[39] Around the country IOUs have implemented other major rate design changes. For example, the rate design researcher, Ahmad Faruqui, found that, as of July 2015, ten IOUs offer residential demand charges.[40] For example, NV Energy offers residential critical peak pricing.[41]

The functionality of PGE's smart meters would allow it to implement a greater degree of dynamic pricing.[42] Given the potential efficiency and environmental gains from dynamic pricing, Staff believes an exploration of additional dynamic pricing options will be a valuable endeavor.

Q. Does Staff have any other rate design considerations?

A. Yes, Staff notes that PGE is unique among Oregon electric IOUs in offering rates without demand charges for commercial customers with peak demands up to 30 kW and in excess of 3,000 monthly kWh. Shortly after PGE completes its Customer Engagement Transformation, Staff plans to examine whether PGE's Schedule 32 should be restructured to conform more closely to Pacific Power's Schedule 28 and Idaho Power's Schedule 9. Staff believes the process to phase Schedule 32 customers onto a demand charge will be

[38] Staff/1304, St. Brown/7, San Diego Gas and Electric Tariff.
[39] Staff/1304, St. Brown/8, Puget Sound Energy, Inc. Tariff.
[40] Staff/1304, St. Brown/9, Faruqui, Ahmad, "Residential Rates for the Utility of the Future," Grid Edge World Forum, June 22, 2016, page 19, http://www.brattle.com/system/publications/pdfs/000/005/304/original/Residential_Rates_for_the_Utility_of_the_Future_6.22.16.pdf?1466788062
[41] Staff/1304, St. Brown/10, NV Envery Tariff.
[42] See Hledik, Ryan, Ahmad Faruqui, and Lucas Bressan, "Demand Response Market Research: Portland General Electric, 2016 to 2035," The Brattle Group, January 2016, https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning

cooperative because, “with respect to Schedule 32, PGE is not necessarily opposed to exploring the implementation of distribution demand charges at some future date after PGE has completed the necessary infrastructure associated with the Customer Engagement Transformation to support such a change.”[43]

[43] Staff/1305, St. Brown/12, PGE’s response to Staff DR 639.

ISSUE 5: PGE'S SCHEDULE 6 PRICING PILOT

Q. Please describe PGE's Schedule 6 Pricing Pilot.

A. Residential customers can optionally enroll in PGE's Schedule 6 Pricing for the purpose of PGE's studying customer response to time varying rates. As of April 24, 2017, PGE has deferred $1,263,472 in costs related to its Schedule 6 pricing pilot.[44] PGE states, "the term for the Schedule 6 Residential Pricing Pilot ends April 30, 2018. PGE may request to extend the pilot or use the results to inform and request to modify its residential time of use option."[45]

Q. Given that PGE's Schedule 6 Pricing Pilot will run at least until 2018, what is Staff's recommendation?

A. For the benefit of its customers, Staff recommends either that PGE file a request to amortize prudent expenses incurred for its Schedule 6 pricing pilot; or, that the Commission direct PGE to file rates in compliance to the Commission's order in this docket to amortize the expenses over a two-year period. This will benefit ratepayers because PGE earns interest at a lower rate once deferred amounts have been authorized for amortization.

Q. Does Staff have any other recommendations related to PGE's study of time varying rates?

A. Yes, in Staff's initial comments in PGE's LC 66 IRP, Staff included a graph from the Regulatory Assistance Project which demonstrated that, throughout multiple studies, critical peak pricing resulted in the greatest reduction to peak

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[44] Staff/1305, St. Brown/13, PGE response to Staff DR No. 538.
[45] Staff/1305, St. Brown/14, PGE Response to Staff DR No. 539.

electricity usage.[46] PGE's Schedule 6 does not include any critical peak pricing options, thus Staff encourages PGE to include critical peak pricing in any future modifications.

[46] See LC 66 Staff's Initial Comments (January 24, 2017) at 12.

ISSUE 6: TEMPORARY SERVICE

Q. Please describe the issue.

A. Each year PGE receives thousands of requests for temporary electricity service, such as for construction sites or food trucks. Periodically, Staff investigates measures of PGE's service quality. Related to this issue, Staff investigated whether the speed that PGE connects temporary service customers meets customers' needs and conforms to standard practice. On average, PGE takes **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** days to complete a temporary service connection.[47] Confidential Exhibit/1303, St. Brown/5 depicts a histogram of the average time it takes PGE to complete a temporary service connection.

Q. Has Staff received complaints related to the length of time PGE takes to connect temporary service?

A. Yes, the Commission's Consumer Services Section receives these types of complaints regularly.

Q. Do any Oregon IOU tariffs specify the expected length of time required to connect temporary service?

A. No.

Q. What is the average length of time it takes to connect non-temporary electricity service in the United States?

A. The World Bank's Annual "Doing Business" report tracks business regulations around the world. The June 2016 report found that it took an average of 89.6

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[47] Staff/1303, St. Brown/4, PGE Response to Staff DR No. 422, provided as a digital file.

days to connect electricity to a newly constructed warehouse in the U.S. Comparatively, it took just 18.0 days in South Korea, the most rapid country.[48]

Q. Please describe what Staff learned from the Company's confidential response to Staff DR 423.

A. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Confidential Exhibit Staff/1303, St. Brown/6 displays the number of cancelations of temporary service requests in 2016 by month.

Q. What is Staff's recommendation for temporary service?

A. Staff recommends that the PGE adopt temporary service quality of service measures. For example, Pacific Power's Rule 25 provides monetary credits to customers if the Company does not switch power on within 24 hours of receiving a request when no construction is required or does not provide an estimate of the cost of new service within 15 working days.

Staff recommends that PGE adopt a similar service quality goal for temporary service requests. Staff would like to see customers get temporary service in less than 15 working days whenever extensive construction of utility infrastructure is not required. Staff was able to find published documents online

[48] Staff Exhibit 1304, St. Brown/11, The World Bank, "Doing Business, Measuring Business Regulations: Getting Electricity," June 2016. Accessed June 5, 2017 at: http://www.doingbusiness.org/data/exploretopics/getting-electricity

indicating potential shorter wait times than 15 days for CenterPoint Energy in Texas and ConEdison in New York.[49] At this time, because PGE is the expert in this area, Staff recommends that in its Reply Testimony, PGE:

1. Comment on whether 15 working days is manageable as a service quality goal to connect temporary service;
2. Describe how PGE envisions compensating customers if it cannot meet its service quality goals.

Staff looks forward to continuing to address this issue in Staff's Rebuttal Testimony.

[49] Neither of these links are conclusive, but rather hint that some service connections in Texas and New York might be completed in less than 15 days. Staff Exhibit 1304/St. Brown/12-13.

ISSUE 7: PGE'S ENERGY TRACKER

Q. Please describe the Energy Tracker issue.

A. On January 3, 2017, the PUC received a complaint from one of PGE's residential customers about the limited functionality of PGE's online Energy Tracker feature. The feature displays customer's hourly usage with about a one-day delay for the purpose of helping customers understand their energy usage. The main complaint was that the data did not sync with customer bills.

Q. Do customers find the Energy Tracker valuable for understanding their energy usage?

A. Yes, approximately 6.3 percent of PGE's residential customers utilize the online Energy Tracker feature.[50]

Q. Was PGE able to determine what caused the issue in the customer complaint?

A. Yes, PGE investigated the issue and determined that the likely cause of Energy Tracker usage data differing from billing data was communication issues between the customer's smart meter and PGE. This issue is not expected to continue.

Q. Are there any other issues with PGE's Energy Tracker feature?

A. Yes, while investigating the customer's complaint, Staff identified another shortcoming of PGE's Energy Tracker feature. That shortcoming is that, "the customer's billed usage could differ from the Energy Tracker summed usage if

[50] Staff/1305,St. Brown/15, PGE Response to Staff DR No. 434.

the billing read has a timestamp other than midnight."[51] This is problematic because for all customers with meter reads other than midnight (i.e. most of them), the Energy Tracker will not match their billed monthly usage. Staff speculates that this can be solved with a modification to the coded formulas in the Company's billing system. However, at this time, the Company is switching to a new billing system and does not plan to edit any existing code.

Q. Did PGE plan to improve its Energy Tracker feature so that it matches billing data?

A. Yes, Staff spoke to a PGE representative over the phone who stated PGE plans to replace its Energy Tracker Feature in Q2 of 2018. PGE is aware of the shortcomings of using days rather than hours to match billing cycle data to Energy Tracker data.

Q. What is Staff's recommendation regarding Energy Tracker.

A. Staff recommends that the Company commit to using hours rather than days to match billing cycle data to Energy Tracker data. This will benefit customers because they will be better able to track how their energy usage affects their bill.

Q. Does this conclude your testimony?

A. Yes.

[51] Staff/1305, St. Brown/16, PGE Response to Staff DR No. 439.

CASE: UE 319
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1301

Witness Qualifications Statement

June 16, 2017

WITNESS QUALIFICATIONS STATEMENT

NAME:	Max St. Brown
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Economist Energy Rates, Finance & Audit Division
ADDRESS:	201 High Street SE., Suite 100 Salem, OR. 97301
EDUCATION:	Ph.D., Economics (2013) Washington State University B.S., Economics (2009) Central Washington University

EXPERIENCE:

I have been employed by the Public Utility Commission since July 2015, with my current position being a Senior Utility Economist, in the Utility Program's Energy – Rates, Finance and Audit Division. My current responsibilities include analysis and technical support for rate, finance, and audit related proceedings, with an emphasis on forecasting and marginal cost studies.

Prior to working for the OPUC I served as an Assistant Professor of Economics at Eckerd College in St. Petersburg, FL from 2013 to 2015. I have taught courses including Econometrics, Labor Economics, and Intermediate Microeconomics. As a graduate student at Washington State University I taught six course sections, including Econ of Renewable Energy.

My published research in peer-reviewed academic journals includes a study of the U.S. renewable energy industry and includes international economic impact studies.

I served as a summer fellow at the American Institute for Economic Research during summers 2011 and 2012.

CASE: UE 319
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1302

Exhibits in Support
Of Opening Testimony

June 16, 2017

Exhibit 1302

1. Commercial Group Forecasting Models

ECFS:

$$Y_t = \alpha_0 + \alpha_1 CDD_t + \alpha_2 HDD_t + \alpha_3 ETO_t + \alpha_m I_m + ARIMA\epsilon_t\,(2,0,5)$$

Model notes:
1. *Y* is load.
2. *t* is time period (monthly from January 2004 to October 2016).
3. C*DD* is cooling degree days.
4. *HDD* is heating degree days.
5. ETO is Energy Trust of Oregon Spending/Revenue in PGE's service territory.
6. *m* is month.
7. *I* is an indicator variable taking on a value of 1 if it is the month indicated and 0 otherwise (January to November).
8. $ARIMA\epsilon_t\,(2,0,5)$ indicates that the model has 2 autoregressive terms, 0 differenced terms, and 5 moving average terms.

ECGE:

$$Y_t = \alpha_0 + \alpha_1 CDD_t + \alpha_2 HDD_t + \alpha_3 ETO_t + \alpha_4 OENGVT_t + \alpha_m I_m + ARIMA\epsilon_t\,(2,0,2)$$

Model notes:
1. *OENGVT* is government employment in Oregon.

ECHE:

$$Y_t = \alpha_0 + \alpha_1 CDD_t + \alpha_2 HDD_t + \alpha_3 ETO_t + \alpha_4 OENEHS_t + \alpha_m I_m + ARIMA\epsilon_t\,(1,1,1)$$

Model notes:
1. *OENEHS* is education and health services employment in Oregon.

ECLD:

$$Y_t = \alpha_0 + \alpha_1 CDD_t + \alpha_2 HDD_t + \alpha_3 ETO_t + \alpha_m I_m + ARIMA\epsilon_t\,(1,0,1)$$

ECMC:

$$Y_t = \alpha_0 + \alpha_1 CDD_t + \alpha_2 HDD_t + \alpha_3 ETO_t + \alpha_4 OENEHS_t + \alpha_m I_m + ARIMA\epsilon_t\,(1,0,1)$$

ECOF:

$$Y_t = \alpha_0 + \alpha_1 CDD_t + \alpha_2 HDD_t + \alpha_3 ETO_t + \alpha_4 OENSV_t + \alpha_m I_m + ARIMA\epsilon_t\,(2,0,0)$$

Model notes:
1. *OENSV* is services employment in Oregon.

ECOS:

$$Y_t = \alpha_0 + \alpha_1 CDD_t + \alpha_2 HDD_t + \alpha_3 ETO_t + \alpha_4 OENSV_t + \alpha_m I_m + ARIMA\epsilon_t\,(2,0,2)$$

ECOT:

$$Y_t = \alpha_0 + \alpha_1 CDD_t + \alpha_2 HDD_t + \alpha_3 ETO_t + \alpha_4 OENEHS_t + \alpha_m I_m + ARIMA\epsilon_t\,(2,0,1)$$

ECRT:

$$Y_t = \alpha_0 + \alpha_1 CDD_t + \alpha_2 HDD_t + \alpha_3 ETO_t + \alpha_4 OENNMF_t + \alpha_m I_m + ARIMA\epsilon_t\,(0,0,1)$$

Model notes:

1. *OENNMF* is non-manufacturing employment in Oregon.
2. *NSC7* was omitted because Staff could not find a forecast of that variable.

ECTU:

$$Y_t = \alpha_1 CDD_t + \alpha_2 HDD_t + \alpha_3 ETO_t + \alpha_m I_m + ARIMA\epsilon_t\,(1,1,2)$$

Exhibit 1302

2. Manufacturing Group Forecasting Models

EMFD:

$$Y_t = \alpha_1 OENTNA_t + \alpha_2 ETO_t + \alpha_m I_m + ARIMA\epsilon_t \,(1,1,3)$$

Model notes:
1. *OENTNA* is Oregon non-agriculture employment.

EMHT:

$$Y_t = \alpha_0 + \alpha_1 ETO_t + \alpha_m I_m + ARIMA\epsilon_t \,(0,0,5)$$

EMLB:

$$Y_t = \alpha_1 ETO_t + \alpha_m I_m + ARIMA\epsilon_t \,(1,1,1)$$

EMME:

$$Y_t = \alpha_0 + \alpha_1 ETO_t + \alpha_m I_m + ARIMA\epsilon_t \,(3,0,0)$$

EMOM:

$$Y_t = \alpha_0 + \alpha_1 OENTNA_t + \alpha_2 ETO_t + \alpha_m I_m + ARIMA\epsilon_t \,(3,0,3)$$

EMPP:

$$Y_t = \alpha_0 + \alpha_1 ETO_t + \alpha_m I_m + ARIMA\epsilon_t \,(1,0,1)$$

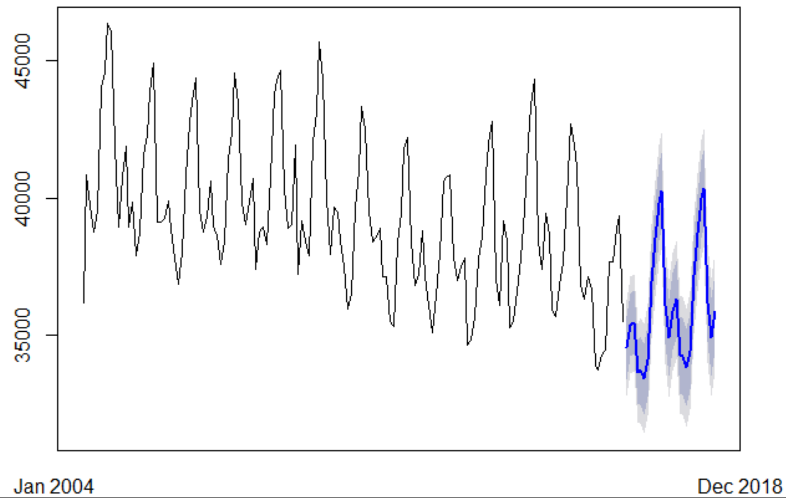
EMOM:

$$Y_t = \alpha_0 + \alpha_1 OENTEM_t + \alpha_2 ETO_t + \alpha_m I_m + ARIMA\epsilon_t \,(1,0,1)$$

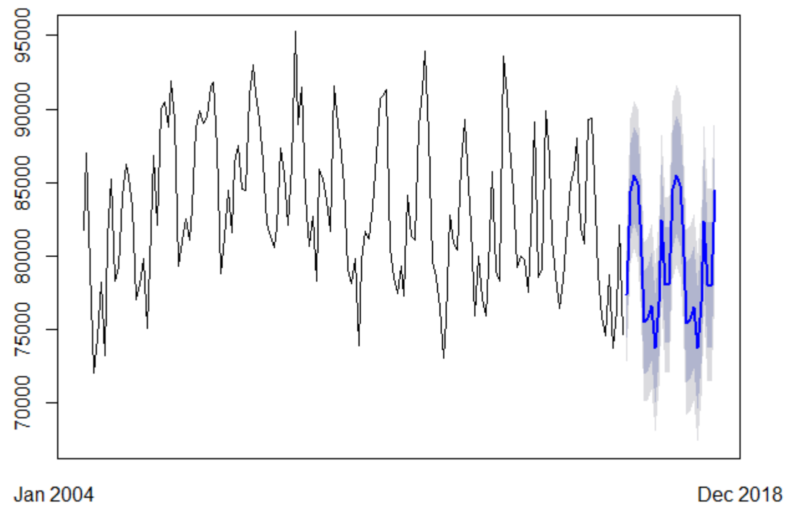
Model notes:
1. *OENTEM* is Oregon transportation equipment manufacturing employment.

Exhibit 1302

Food Stores commercial group



Government and Education commercial group



Health commercial group

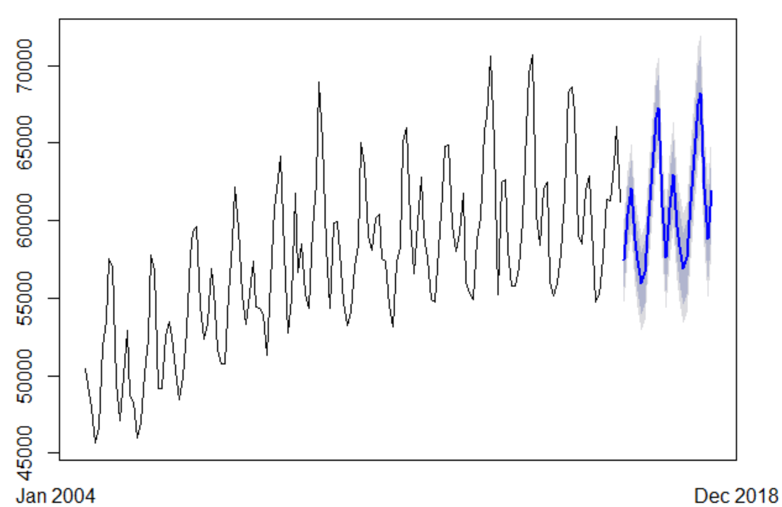
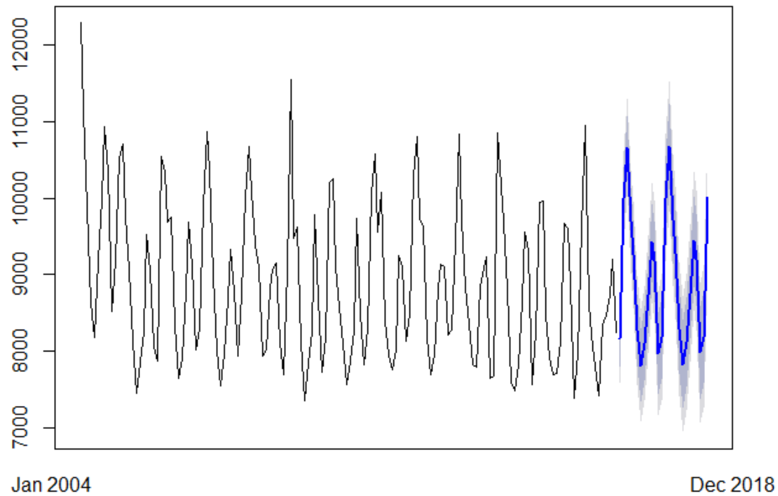
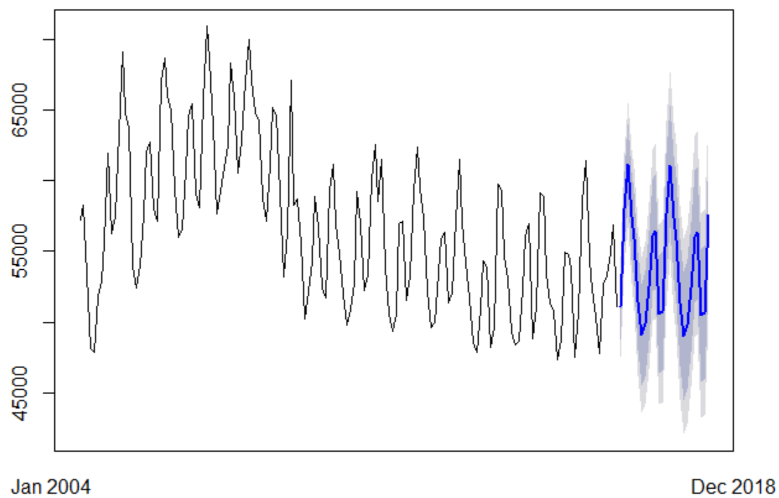


Exhibit 1302

Lodging commercial group



Misc Commercial commercial group



Merchandise Stores commercial group

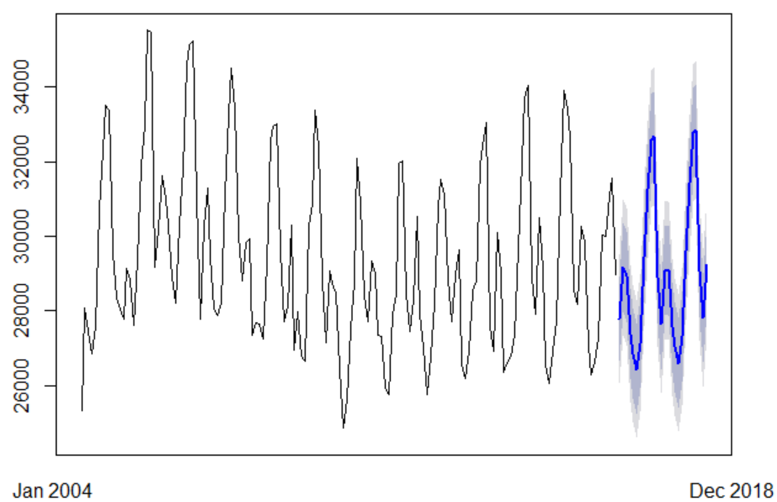
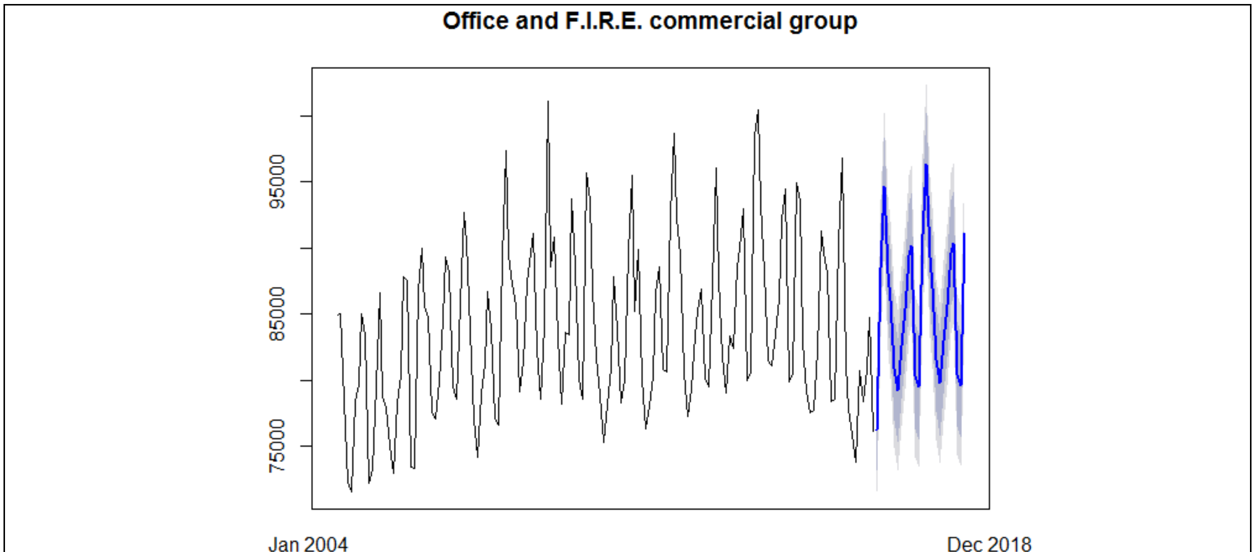
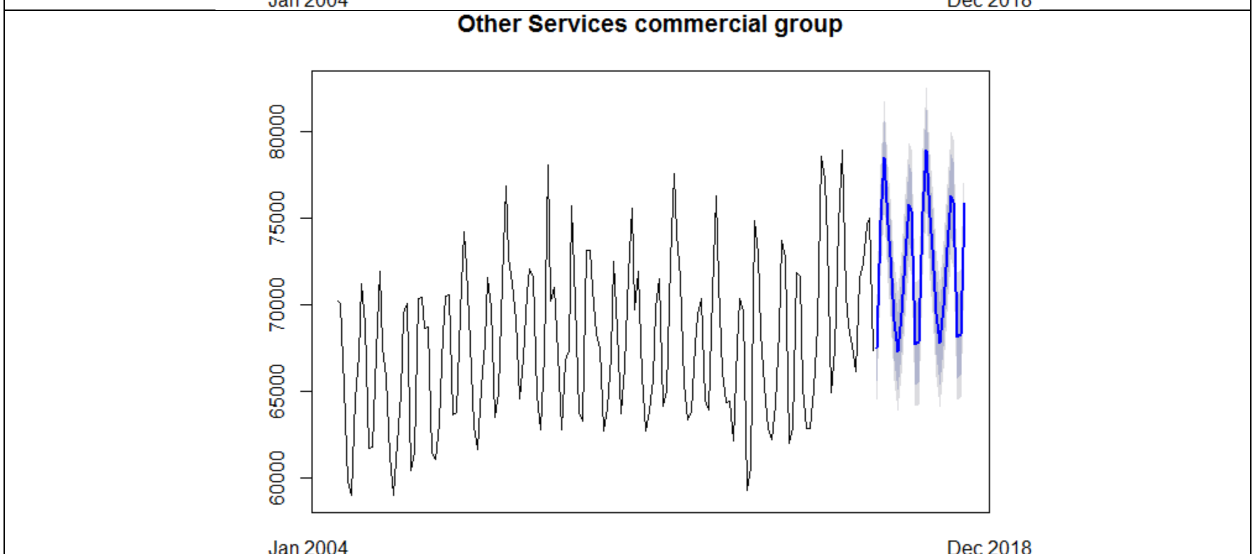
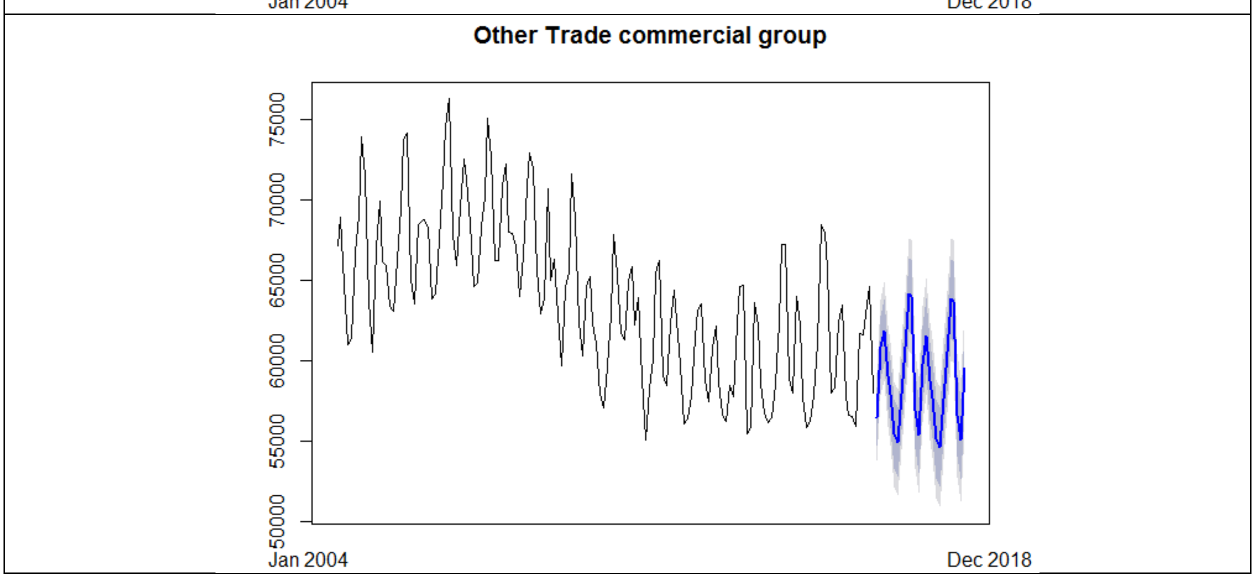


Exhibit 1302







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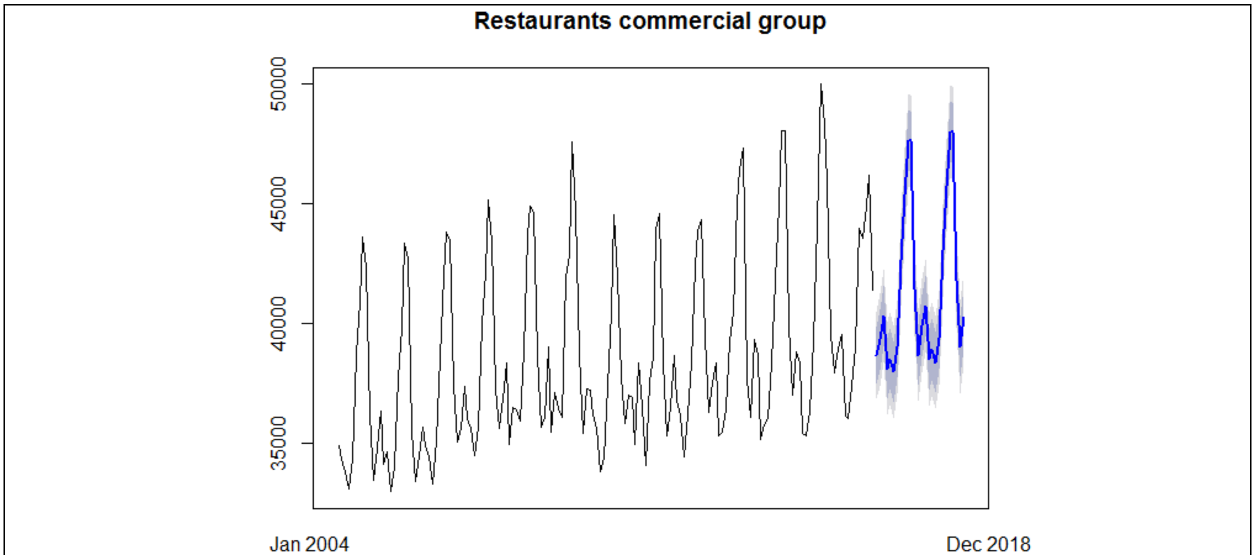


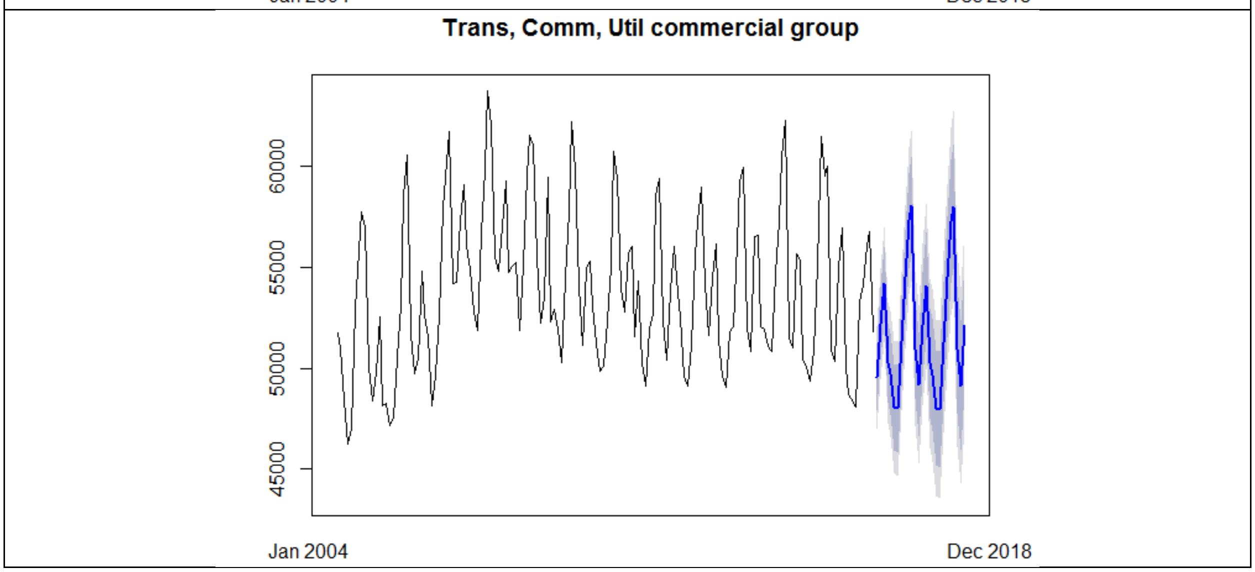
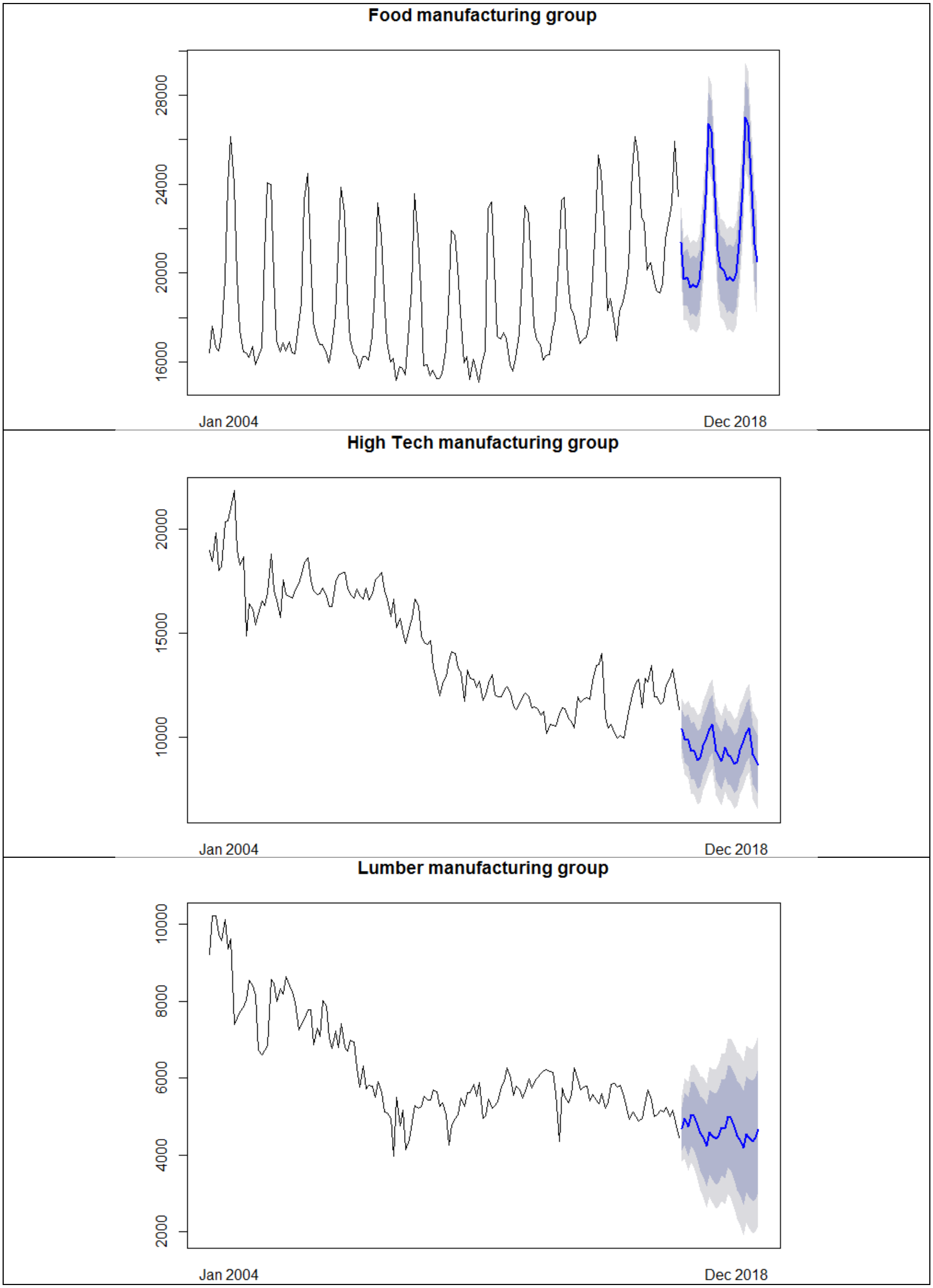


Exhibit 1302



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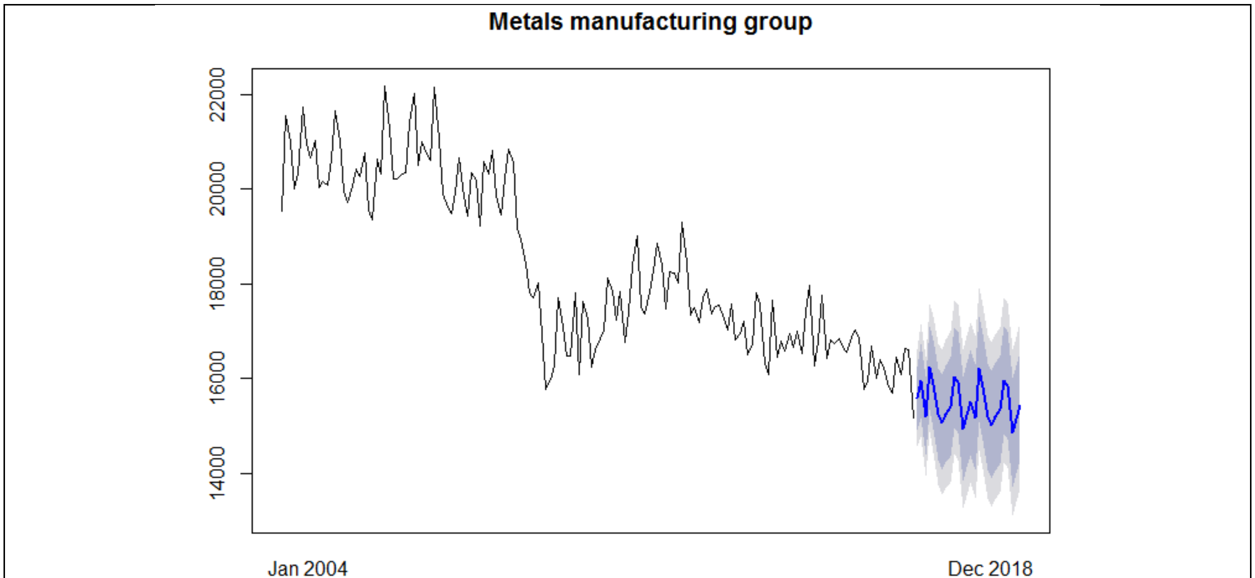

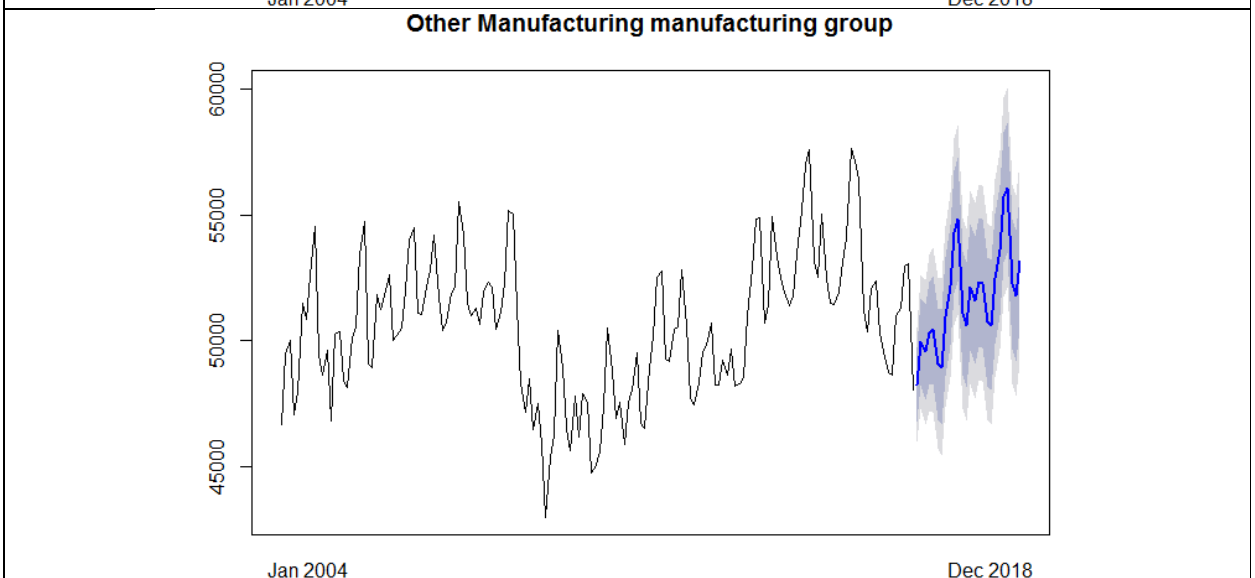

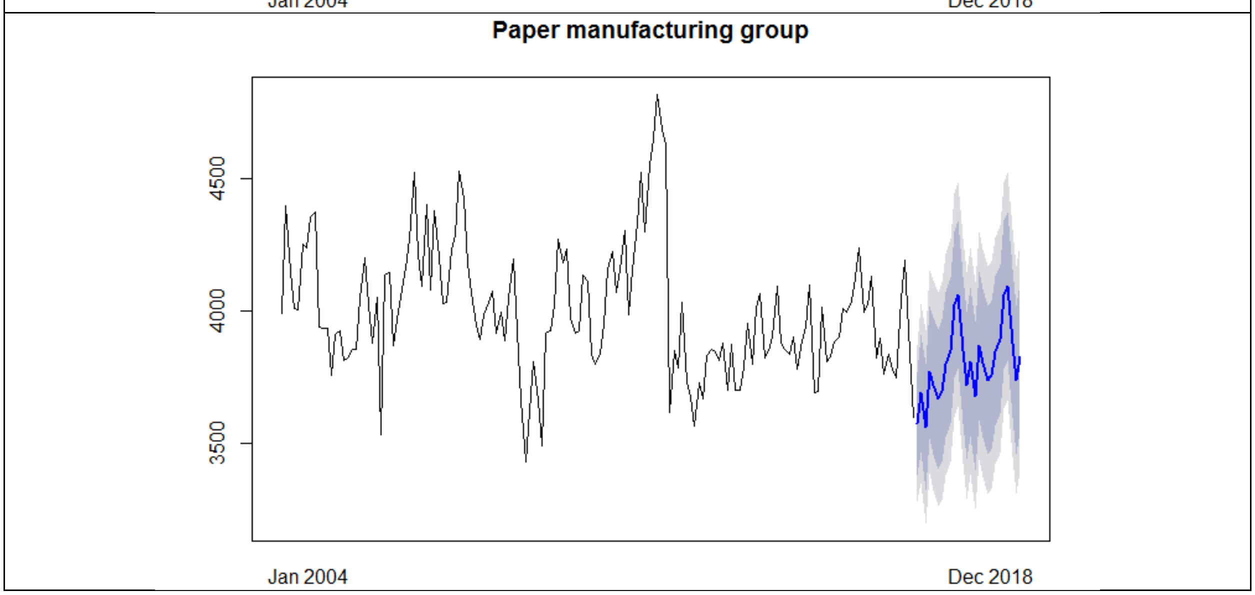

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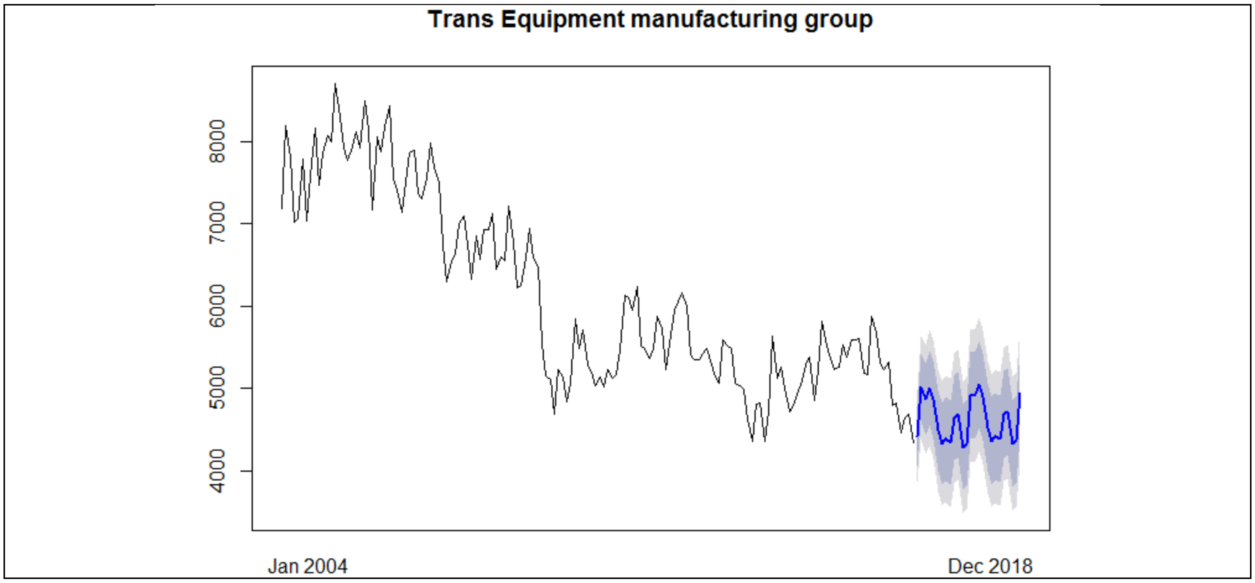


CASE: UE 319
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1303

Exhibits in Support
Of Opening Testimony

June 16, 2017

Exhibit 1303 is confidential and

Is subject to Protective Order No.17-057

CASE: UE 319
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1304

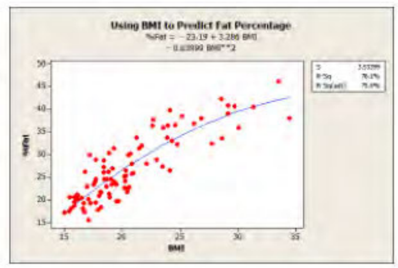
Exhibits in Support
Of Opening Testimony

June 16, 2017

Exhibit 1304

A Tribute to Regression Analysis

Jim Frost · 17 May, 2012



Shhh. I have a secret. Working at Minitab, I should probably say that I love all of its analyses equally. Perhaps it would be OK to love them differently, but equally. However, I've always had a sneaking preference for Minitab's regression analysis. I just can't keep it a secret anymore!

If you promise to keep this secret, I'll give you a special bonus tip at the end of the post. In fact, most of my colleagues here at Minitab don't even know about this one! Seriously!

I've used regression extensively and love it for all of its flexibility. You can use:

- multiple predictor variables
- continuous and categorical variables
- higher-order terms to model curvature
- interaction terms to see if the effect of one predictor depends upon the value of another

That's all cool stuff. But the list leaves out an almost *magical* property of regression analysis. Regression has the ability to disentangle some very convoluted problems. Problems where the predictors seem enmeshed together like spaghetti.

Suppose you're a researcher and you are studying a question that involves intertwined predictors. For example, you want to determine:

- whether socio-economic status or race has a larger effect on educational achievement
- the importance of education versus IQ on earnings
- how exercise habits and diet effect weight
- how drinking coffee and smoking cigarettes are related to heart disease
- if a specific exercise intervention (separate from overall activity levels) increases bone density

These are all research questions where the predictors are likely to be correlated with each other and they could all influence the response variable. How do you untangle this web and separate out the effects? How do you determine which variables are significant and how large of a role does each one play? Regression comes to the rescue!

You Must Control Everything! (Or at least the important variables)

Multiple regression estimates how the changes in each predictor variable relate to changes in the response variable. Importantly, regression automatically controls for every variable that you include in the model.

What does it mean to control for the variables in the model? It means that when you look at the effect of one variable in the model, you are holding constant all of the other predictors in the model. Or "ceteris paribus," as the Romans would've said. You explain the effect that changes in one predictor have on the response without having to worry about the effects of the other predictors. In other words, you can isolate the role of one variable from all of the others in the model. And, you do this simply by including the variables in your model. It's beautiful!

For instance, a recent study assessed how coffee consumption affects mortality. Initially, the results showed that higher coffee consumption is correlated with a higher risk of death. However, many coffee drinkers also smoke. After the researchers included a variable for smoking habits in their model, they found that coffee consumption *lowered* the risk of death while smoking increased it. So, by including coffee consumption, smoking habits, and other important variables, the researchers held everything that is important constant and were able to focus on the role of coffee consumption.

Take note, this study also illustrates how not including an important variable (leaving it uncontrolled) can completely mess up your results.

Exhibit 1304

What to Look For in the Regression Output

To answer questions like these, after you fit and verify that you have a good model, all you need to do is look at the p-value and coefficient for each predictor. If the p-value is low (usually < 0.05), the predictor is significant. Coefficients represent the mean change in the response for one unit of change in the predictor while holding other predictors in the model constant.

For example, if your response variable is income and your predictors include IQ and education (among other relevant predictors), you might see output like this:

Coefficients

Term	Coef	SE Coef	T	P
Constant	483.670	39.5671	12.2241	0.000
IQ	4.796	0.9511	5.0429	0.000
Education	24.215	1.9405	12.4785	0.000

The p-values indicate that both IQ and education are significant. The IQ coefficient shows that an increase of one IQ point increases your earnings by an average of around $4.80, holding everything else in the model constant. Further, an increase in 1 unit of education increases your earnings by $24.22, ceteris paribus.

How To Get Results That You Can Trust

With this great power comes some responsibility. Sorry, but that's the way it always works. For it all to work out correctly you need to do the following:

- Include all of the important variables in your model. Leaving out important variables leaves them uncontrolled and can bias your coefficients (i.e., they're probably wrong).
- You should have good measures for the included variables, or at least include proxy variables for those that are hard to measure.
- Check your residual plots to make sure that your model fits your data.

Correlated Predictors

As we've seen, regression analysis can handle predictors that are correlated, also known as mullticollinearity. Moderate multicollinearity may not be a problem. However, severe multicollinearity is problematic because it can increase the variance of the regression coefficients, making them unstable and difficult to interpret.

For example, IQ and education are probably correlated, as is drinking coffee and smoking. As long as they aren't excessively correlated, it's not a problem. How do you know? VIFs are your friend! Variance inflation factor (VIF) is an easy to use measure of multicollinearity.

VIF values greater than 10 may indicate that multicollinearity is unduly influencing your regression results. If you see high VIF values, you may want to remove some of the correlated predictors from your model.

For **General Regression** in Minitab statistical software, you can display the VIFs by clicking the **Results** button and checking **Display variance inflation factors**.

Closing Thoughts and the Bonus Tip!

Regression gives you the power to separate out the effects of even tricky research questions. You can unravel the intertwined spaghetti noodles by holding all relevant variables constant and seeing the role that each plays.

If you're learning about regression, read my regression tutorial!

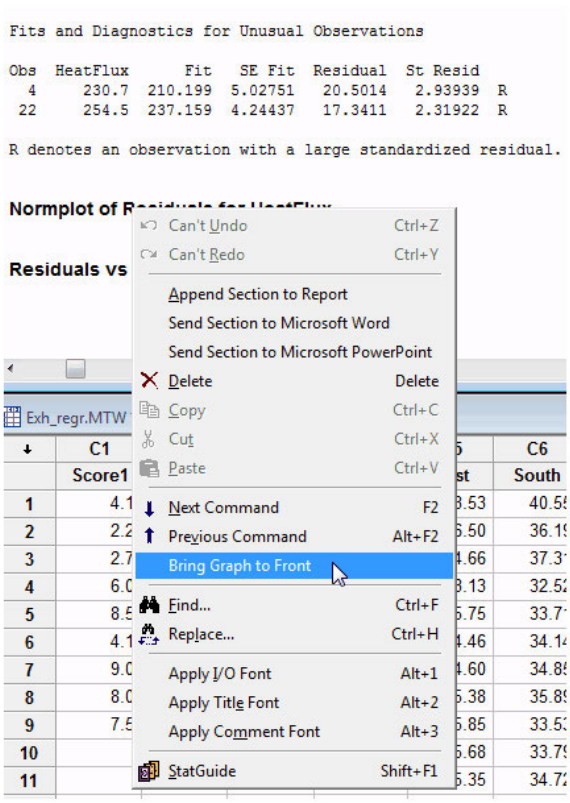
Now, on to the bonus tip! I've learned this tip just recently, even though this feature has been in Minitab for a while. It was also a surprise to my colleagues.

Exhibit 1304

Imagine you're in the process of finding the proper regression model for your data. You have many variables, and you've included the terms for curvature and interactions. You're reducing your model down to just the significant terms and checking the residual plots along the way. The result is a lot of output in the session window and many graphs. It can be difficult to find the specific plots for any given regression model.

There is an easy way to pull up the plots for a specific model. As you scroll down through the session window, just right-click on the heading for the graph and choose **Bring Graph to Front**, as shown below. Voila! The graph for that specific model is visible! This action works for other graphs, as long as you produce them as part of a statistical analysis (e.g. 2-sample t-test, ANOVA, etc).

Have fun with regression!



Jim Frost, "A Tribute to Regression Analysis," *The Minitab Blog*, May 17, 2012. Available at: http://blog.minitab.com/blog/adventures-in-statistics-2/a-tribute-to-regression-analysis.

Exhibit 1304

What is a Zestimate?

The Zestimate® home valuation is Zillow's estimated market value, computed using a proprietary formula. It is not an appraisal. It is a starting point in determining a home's value. The Zestimate is calculated from public and user-submitted data, taking into account special features, location, and market conditions. We encourage buyers, sellers, and homeowners to supplement Zillow's information by doing other research such as:

- Getting a comparative market analysis (CMA) from a real estate agent
- Getting an appraisal from a professional appraiser
- Visiting the house (whenever possible)

Zillow also produces a Zestimate forecast, which is Zillow's prediction of a home's Zestimate one year from now, based on current home and market information. Learn more about the Zestimate forecast.

Zillow also provides a Rent Zestimate estimated monthly rental price. Learn more about the Rent Zestimate.

FAQs

What's the Value Range?

My Zestimate is too low - or too high. What gives?

I just changed the home facts. When will my Zestimate update?

How does the amount of data affect it?

Is a Zestimate an appraisal?

How do we come up with the Zestimate and what's in the formula?

Why do I see home values for the past?

Do you ever change prior Zestimates?

Does the Zestimate algorithm ever change?

Yes, a team of statisticians is working every day to make the Zestimate more accurate. Since Zillow's inception in 2006, we have deployed three completely new versions of the algorithm (2006, 2008 and 2011), but incremental improvements are made between major upgrades with new iterations being deployed regularly.

Zillow.com, "Does the Zestimate algorithm ever change?" Accessed May 31, 2017. Available at: https://www.zillow.com/zestimate/#faq-6

Exhibit 1304

EVs are here. Try to keep up.
CHARGED
ELECTRIC VEHICLES MAGAZINE

Utility demand charges and electric vehicle supply equipment

Posted October 31, 2013 by Jeffrey Wishart & filed under Features, Infrastructure Features.

Jeffrey Wishart, *Senior Principal Engineer at ECOtality since 2009, conducts research and development on products and services in the areas of energy, the environment, and advanced transportation. In addition to his supervisory position at ECOtality, Dr Wishart worked for several years at a utility company in Queensland, Australia, conducting research into emerging energy technologies.*

What are demand charges?

One of the barriers that EVs have faced is convincing business owners and government decision-makers to host public charging stations. The difficulty is especially acute for DC Fast Chargers (DCFCs), not just because of installation and energy costs and permitting headaches, but also due to high power costs that show up as "demand charges" on the host's utility bill.

A demand charge is a fee imposed by a utility, typically for commercial properties, for the peak power used during a billing cycle, regardless of the amount of energy drawn at this power rate.

In contrast to the total energy usage that is the more familiar utility charge, a demand charge is triggered by a one-time occurrence of an elevated power level (usually an average over a 15-minute interval) and is not a cumulative charge. Demand charge rates are specified in $/kW, and are usually incurred when the peak power used during a billing cycle rises above a specified threshold, but they are sometimes incurred for any power level above zero. Certain utilities even levy a yearly peak power demand charge.

Simply put, demand charges are the method by which utilities penalize high power consumption during peak demand periods.

This could very well deter commercial EVSE usage and negatively affect the nascent EV industry.

Demand charges can add significantly to the utility bill for an EVSE host, and can make EVSE hosting cost-prohibitive. As a result, hosts may attempt to recoup the demand charges by increasing fees for vehicle charging. This could very well deter commercial EVSE usage and negatively affect the nascent EV industry.

Demand charges have less of an impact on AC Level 2 EVSE deployment, due to a relatively low output power that is often below the demand charge threshold. However, a cluster of AC Level 2 units can incur demand charges with their aggregate power demand, if on the same service. Conversely, the higher power levels of a single DCFC incur demand charges much more frequently.

Real-world demand charge examples

While deploying DCFCs around the country for the The EV Project, ECOtality worked with many different utilities and encountered a variety of different demand charge rates. But there are also utilities that do not impose demand charges for DCFC installations, including Tucson Electric Power, Alameda Municipal Power, Silicon Valley Power, Pacific Gas and Electric, City of Palo Alto Utilities, and all of the utilities in the state of Tennessee.

Among the many utilities that do have demand charges on the books, the three with the highest rates (that we encountered) are all in California. Looking at the worst-case scenario, for example on a summer day during the peak period, the following demand charges would be incurred.

- San Diego Gas and Electric: up to $30.68 per kW
- Southern California Edison: up to $29.20 per kW
- Burbank Water and Power: up to $21.21 per kW

Using those rates, an analysis of the demand charges associated with a particular DCFC duty cycle can be developed[1]. Assuming the DCFC to be the only load on the meter, and using the published base, energy, and demand charge rates for the three high demand charge utilities above, the monthly (30.4 days) bill for a DCFC installation with the assumed duty cycle could reach:

- San Diego Gas and Electric: $58.22 (base) + $230.53 (energy) + $1,840.80 (demand), for a total of $2,149.55. **The demand charge would be 86% of the total monthly bill.**
- Southern California Edison: $134.17 (base) + $211.13 (energy) + $1,752.00 (demand), for a total of $2,097.30. **The demand charge would be 84% of the total monthly bill.**
- Burbank Water and Power: $16.27 (base) + $274.11 (energy) + $1,272.60 (demand), for a total of $1,562.98. **The demand charge would be 81% of the total monthly bill.**

Exhibit 1304

As you can see from these examples, devising solutions to the demand charge problem is imperative to the growth of the industry.

How to avoid demand charges?

There are a variety of different methods for avoiding or reducing demand charges. However, it is unlikely that any one will be optimal for each specific location, so it's important to evaluate all options on a case-by-case basis.

The first step is to determine the following information for a given DCFC installation:

- What is the expected peak demand for the site owner in a billing period? Over how much of the 15-minute interval does the peak demand span?
- What is the average site demand?
- What is the utility rate structure? Is there a yearly maximum average power demand charge in addition to the billing cycle maximum average power demand charge?
- What is the tolerance for an incurred demand charge, i.e., how much is the EVSE host willing to pay in demand charges?

Once these parameters are specified, the next step is to choose from the possible methods for reducing the demand charge. ECOtality came up with six ways (although there are likely several other possibilities):

1. Never allow the overall site power demand to exceed a specified value.
2. Attempt to ensure that the average power over the interval is less than or equal to a specified value.
3. Attempt to recoup the demand charge cost through structured pricing for EVSE charging.
4. Add an energy storage system that buffers the EVSE unit from high power demands during charging.
5. Aggregate demand among multiple EVSE installations into one demand charge calculation, taking advantage of the diversity that may exist in individual unit usage.
6. Provide demand response capability to the utility to either offset or circumvent demand charges.

[A seventh "solution" would be to work with utilities to create a tariff that exempts EVSE usage from demand charges. Since this is within the purview of the utility, we'll focus only on the EVSE side for demand charge avoidance and reduction.]

The six possibilities vary considerably in cost and effort involved, as well as in likely effectiveness at reducing the demand charge without simultaneously reducing the utility of the DCFC.

1. Never allow the overall site power demand to exceed a specified value

This method is the most conservative and least expensive of the six. It basically involves de-rating the DCFC so that the EVSE host can be assured that the unit will not exceed the value that is the difference between the demand charge tolerance and the expected peak demand of the host. Historical data can reveal the expected peak site demand. With the peak site demand known, the maximum DCFC power allowable to obtain the tolerated demand charge can be calculated, and the DCFC can then be electrically limited at the time of installation or on an individual charge basis. The drawback is that a de-rated DCFC means a slower charge, and the amount of required de-rating could be overestimated. Thus, EV owners may not take kindly to this reduced charge rate and the increased time it takes to charge.

2. Attempt to ensure that the average power over the interval is less than or equal to a specified value

This tactic depends on having accurate historical data and/or a very predictable site demand. If the DCFC is on its own service, the complexity is reduced considerably. This method requires de-rating of the DCFC just as in Method 1; however, the de-rating will be just enough to ensure that the average power during the 15-minute interval will not incur a demand charge exceeding the tolerance threshold. Although the de-rating is less severe, the charge will still be slower, and there is a greater chance of exceeding the tolerance threshold if the DCFC is on a shared service.

3. Attempt to recoup the demand charge cost through structured pricing for EVSE charging

This method is conceptually simple, and there is no de-rating of the DCFC unit. The EVSE host sets either a single rate or tiered rate structure (for different charge power rates) in an attempt to amortize the demand charge cost over all of the vehicles that are charged during a billing period. The host may actually make a larger profit with this method, but could also experience a larger deficit if the predicted usage is inaccurate. The host might also see a backlash if customers do not like having different charging rates available, or if the usage is underestimated and the rates are higher than needed to cover the demand charge incurred.

4. Add an energy storage system that buffers the EVSE unit from high power demands during charging

Pairing the DCFC with stationary energy storage would buffer the power demand of the DCFC, and reduce or eliminate the need to exceed the demand charge threshold

Pairing the DCFC with stationary energy storage would buffer the power demand of the DCFC, and reduce or eliminate the need to exceed the demand charge threshold. The stationary battery pack is replenished by grid electricity, which can be timed to take advantage of off-peak rates and be at sufficiently low power rates to avoid (or at least minimize) demand charges. This configuration is also useful for future advancements in grid-DCFC connections like vehicle-to-grid (V2G) where the flow of electricity is bidirectional. Naturally, the drawback to this strategy is the additional expense of the energy storage, although a return on investment (ROI) can be developed via the savings on demand charges.

5. Aggregate demand among multiple EVSE installations into one demand charge calculation, taking advantage of the diversity that may exist in individual unit usage

This involves putting multiple DCFCs on one service or developing an arrangement with the utility to treat multiple DCFC installations as a single load, and then relying on demand diversity so that the aggregate demand charge is less than the total of individual demand charges. For this to work, not all DCFCs can be at the peak load at the same time, which may imply that the utilization factor of the DCFCs cannot be very high. Demand charges will be incurred, so this method is only a way to decrease demand charges, not avoid them.

6. Provide demand response capability to the utility to either offset or circumvent demand charges

This method incorporates some utility policies that are already in place and applies them to DCFCs. Utilities are very eager to work with customers to reduce peak loads not only to avoid grid failures but also to postpone generation, transmission, and distribution capacity increases, which require heavy capital expenditures. To accomplish these goals, utilities offer incentives, such as time-of-use (TOU) rates that push customers to use electricity more during off-peak times, and demand response programs whereby a customer can be compensated for reducing their electricity demand when required by the utility. EVSE hosts could either sign up for demand response programs directly with the utility, or, more likely, sign with an aggregator, a company that signs up a number of electrical load owners, and then takes a cut of the utility's incentive while eliminating the risk of not meeting the utility's requirements for demand response in situations where there is no vehicle charging. Demand charges will still be incurred by the EVSE host, but the payments from the utility or aggregator should offset the costs and perhaps even result in a net benefit.

Case-by-case

This decision must be made on a case-by-case basis, and will largely depend on the tolerance of the DCFC host to large and varying demand charges.

Analyzing the methods presented here leads to several conclusions. First, it's important that reliable historical energy use data is available for any prospective DCFC site. Each site must be vetted thoroughly for the appropriateness of DCFC deployment, including the obvious permitting and installation costs and complexities, but also from the standpoint of site demand data reliability and uniformity. If the data are unavailable or the demand varies widely, the site may not be suitable for a DCFC unit. This decision must be made on a case-by-case basis, and will largely depend on the tolerance of the DCFC host for large and varying demand charges.

Some of the charge reduction methods will require an energy management system or remote EVSE monitoring and demand control capabilities. These features are more easily included in "smart" EVSE units rather than in "dumb" EVSE units. While a dumb charger may cost less upfront, as with most things, cheaper is not always better in the long term.

These various solutions offer different degrees of certainty. An EVSE host needs to balance the desire to reduce demand charges on one hand with maintaining the level of service his customers/users expect from the EVSE charging on the other.

This article originally appeared in Charged Issue 10 – OCT 2013

Jeffery Wishart, "Utility demand charges and electric vehicle supply equipment," *Charged Electric Vehicles Magazine*, October 31, 2013. Available at: https://chargedevs.com/features/utility-demand-charges-and-electric-vehicle-supply-equipment/

Exhibit 1304

SDGE

San Diego Gas & Electric Company
San Diego, California

Revised Cal. P.U.C. Sheet No. 28651-E

Canceling Revised Cal. P.U.C. Sheet No. 28519-E

Sheet 1

SCHEDULE DR

RESIDENTIAL SERVICE
(Includes Rates for DR-LI)

APPLICABILITY

Applicable to domestic service for lighting, heating, cooking, water heating, and power, or combination thereof, in single family dwellings, flats, and apartments, separately metered by the utility; to service used in common for residential purposes by tenants in multi-family dwellings under Special Condition 8; to any approved combination of residential and nonresidential service on the same meter; and to incidental farm service under Special Condition 7.

This schedule is also applicable to customers qualifying for the California Alternate Rates for Energy (CARE) Program and/or Medical Baseline, residing in single-family accommodations, separately metered by the Utility, and may include Non-profit Group Living Facilities and Qualified Agricultural Employee Housing Facilities, if such facilities qualify to receive service under the terms and conditions of Schedule E-CARE. The rates for CARE and Medical Baseline customers are identified in the rates tables below as DR-LI and DR-MB rates, respectively.

Customers on this schedule may also qualify for a semi-annual California Climate Credit $(29.62) per Schedule GHG-ARR.

TERRITORY

Within the entire territory served by the Utility.

RATES

Total Rates:

Description - DR Rates	UDC Total Rate		DWR-BC Rate	EECC Rate + DWR Credit		Total Rate	
Summer:							
Baseline Energy ($/kWh)	0.06182	R	0.00549	0.14106	I	0.20837	I
Above 130% of Baseline	0.28315	I	0.00549	0.14106	I	0.42970	I
Winter:							
Baseline Energy ($/kWh)	0.11507	I	0.00549	0.07196	I	0.19252	I
Above 130% of Baseline	0.31956	I	0.00549	0.07196	I	0.39701	I
Minimum Bill ($/day)	0.329					0.329	

Description -DR-LI Rates	UDC Total Rate		DWR-BC Rate	EECC Rate + DWR Credit		Total Rate	
Summer – CARE Rates:							
Baseline Energy ($/kWh)	0.06135	R	0.00000	0.14106	I	0.20241	I
Above 130% of Baseline	0.28268	I	0.00000	0.14106	I	0.42374	I
Winter – CARE Rates:							
Baseline Energy ($/kWh)	0.11460	I	0.00000	0.07196	I	0.18656	I
Above 130% of Baseline	0.31909	I	0.00000	0.07196	I	0.39105	I
Minimum Bill ($/day)	0.164					0.164	

(Continued)

1C9

Advice Ltr. No. 3034-E

Decision No. 16-12-053

Issued by
Dan Skopec
Vice President
Regulatory Affairs

Date Filed Jan 17, 2017
Effective Mar 1, 2017
Resolution No.

San Diego Gas and Electric, "Schedule DR, Residential Service," Effective March 1, 2017.
http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_DR.pdf

Exhibit 1304

Thirty-Third Revision of Sheet No. 7
Canceling Thirty-Second Revision
WN U-60 of Sheet No. 7

PUGET SOUND ENERGY, INC.
Electric Tariff G

SCHEDULE 7
RESIDENTIAL SERVICE
(Single phase or three phase where available)

1. **AVAILABILITY:** (T)
   1. This schedule is limited to residential service, which means service that is delivered through one meter to a single-family unit and is used principally for domestic purposes, even though such service may incidentally be used for nondomestic purposes. Electric service for nondomestic use may be separately metered and served under the provisions of the applicable general service schedule, provided that such service does not include single-family units. (M) (D)

      In addition, residential service means service to an adult family home, which means a residential home in which a person or persons provide personal care, special care, room, and board to more than one but not more than six adults who are not related by blood or marriage to the person or persons providing the services. In accordance with RCW 70.128.140(2), adult family homes must be considered as residential for utility rate purposes. (M)

   2. If this schedule is applied to transient occupancy in separately metered living units, billing shall be in the name of the owner on a continuous basis.

   3. Single-phase motors rated greater than 7-1/2 HP shall not be served under this schedule except by the express written approval of the Company.

   4. Space conditioning and water heating capacities shall be energized in increments of 6 KW or less by a thermostat, low voltage relay, or suitable time delay equipment.

   5. Customers requiring three-phase service under this schedule will be required to contribute the incremental cost of three-phase facilities to provide such service.

2. **MONTHLY RATE:** (T)
   Basic Charge: $7.49 single phase or $17.99 three phase

   Energy Charge:
   $0.085578 per kWh for the first 600 kWh (O)
   $0.104157 per kWh for all over 600 kWh (O)

(M) Transferred from Sheet No. 7-A

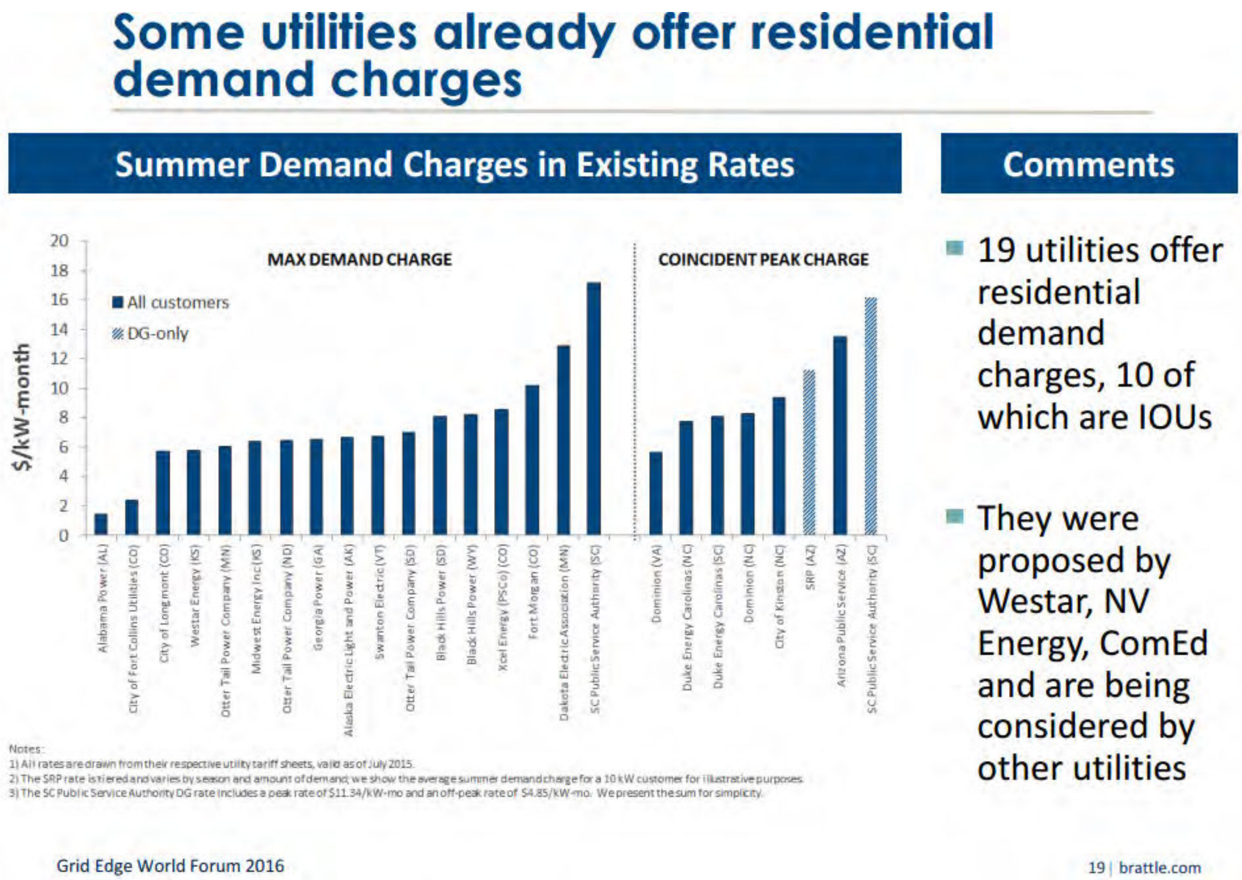
Issued: October 9, 2013 **Effective:** November 16, 2013
Advice No.: 2013-21

Issued By Puget Sound Energy, Inc.

By: Ken Johnson **Title:** Director, State Regulatory Affairs

Puget Sound Energy, Inc., "Schedule 7, Residential Service," Effective November 16, 2013, https://pse.com/aboutpse/Rates/Documents/elec_sch_007.pdf

Exhibit 1304



Faruqui, Ahmad, "Residential Rates for the Utility of the Future," Grid Edge World Forum, June 22, 2016, page 19, http://www.brattle.com/system/publications/pdfs/000/005/304/original/Residential_Rates_for_the_Utility_of_the_Future_6.22.16.pdf?1466788062

Exhibit 1304

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road, Reno, Nevada — **2nd Revised** — PUCN Sheet No. **64I(4)**
Tariff No. **Electric No. 1** — Cancelling **1st Revised** — PUCN Sheet No. **64I(4)**

Schedule No. ODM-1-CPP (N)

OPTIONAL DOMESTIC SERVICE MULTI-FAMILY CRITICAL PEAK PRICE

APPLICABLE

Service under this schedule is available as an option to the regular, non-TOU service under Schedule No. DM-1. This schedule is available to all domestic and other power service that would otherwise be served under Schedule No. DM-1. Customers taking service under Schedule NSMO-1 are not eligible for service under this rate schedule.

TERRITORY

Entire Nevada service area, as specified.

RATES

This schedule contains a Critical Peak Price (CPP) structure overlaid on the base TOU pricing structure of Schedule ODM-1-TOU. The Critical Peak Price rate for this schedule only applies when a CPP Event is called. As detailed in Special Conditions 3 and 4, the total CPP Event hours are limited to a maximum of 70 hours per year (12 to 14 events for 5 hours each event from 1 PM through 6 PM) during the three Summer Season months. Events will only be called on non-holiday weekdays. In exchange for accepting the inclusion of critical peak events and prices during a limited number days and hours of the Summer Season, Customers serviced under Schedule ODM-1-CPP are subject to lower on-peak rates (compared to the ODM-1-TOU schedule) in each and every hour of the on-peak period during which a CPP Event is not applicable.

In order to fully develop marketing, education materials and tools to help Customers be successful on this rate, this schedule will not be in effect for Customers until April 1, 2018.

The charges applicable to this rate schedule are set forth in the currently effective Statement of Rates and are incorporated herein by reference. Bundled rates can be found beginning on PUCN Sheet No. 63G.

MINIMUM CHARGE

The minimum charge for service hereunder shall be the Basic Service Charge.

LATE CHARGE

The Utility may charge a fee as set forth in Schedule MC for the late payment of a bill.

(Continued) (N)

Issued: **12-30-16** Effective: **01-01-17** Advice No.: **583-E**	Issued By: Shawn M. Elicegui Senior Vice President	

NV Energy, "Optional Domestic Service Multi-family Critical Peak Price," Effective January 1, 2017, https://www.nvenergy.com/company/rates/nnv/electric/schedules/images/ODM_1_CPP_Electric_North.pdf

Exhibit 1304

THE WORLD BANK
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English Search

DOING BUSINESS
Measuring Business Regulations

DATA RANKINGS REPORTS SUBNATIONAL METHODOLOGY RESEARCH BUSINESS REFORMS LAW LIBRARY CONTRIBUTORS ABOUT MEDIA

Data / Getting Electricity

Getting Electricity

Select a topic

This topic tracks the procedures, time and cost required for a business to obtain a permanent electricity connection for a newly constructed warehouse. In addition to assessing efficiency of connection process, Reliability of supply and transparency of tariff index measures reliability of power supply and transparency of tariffs and the price of electricity. The most recent round of data collection for the project was completed in June 2016. See the methodology for more information.

Data | Distance to Frontier | What is Measured | Why it Matters | DB Reforms | Good Practices | FAQ | Other Resources

= Subnational *Doing Business* data available. = Multi-city data for same economy is available.

Global

Economy	Getting Electricity DTF	Getting Electricity rank	Procedures (number)	Time (days)	Cost (% of income per capita)	Reliability of supply and transparency of tariff index (0-8)
Economy						
Korea, Rep	99.88	1	3.0	18.0	38.3	
United States	83.39	36	4.8	89.6	24.4	

The World Bank, "Doing Business, Measuring Business Regulations: Getting Electricity," June 2016. Accessed June 5, 2017 at: http://www.doingbusiness.org/data/exploretopics/getting-electricity

Exhibit 1304

Sample Service Requests and Related Steps

We have outlined five scenarios and the corresponding steps you should follow to establish service, along with instructions for your new homeowners on how to establish electricity service when they move into the home.

Establish Temporary Service - Construction Needed

1. Contact your CenterPoint Energy service consultant to initiate construction, obtain addresses (if needed) and establish an ESI-ID. Use the listing on the back of the Builder Blueprint for the contact information of your local CenterPoint Energy Service Center.
2. Wait 48 hours while CenterPoint Energy generates your new ESI-ID.
3. Submit your T-SAW request via fax or phone to Reliant after the 48-hour period has elapsed.
4. Reliant submits a move-in (MVI) request to ERCOT.
5. CenterPoint Energy receives an MVI request from ERCOT and installs your new meter.
6. Electricity service will start within three to seven business days after CenterPoint Energy receives MVI request from ERCOT.*
7. You will receive an initial bill from Reliant.

Establish Temporary Service - No Construction Needed

"No construction needed" applies when temporary service is established in an area where there is an existing secondary CenterPoint Energy service within 60 feet of the temporary service location.

1. Contact CenterPoint Energy to establish an ESI-ID.
2. Wait 48 hours while CenterPoint Energy generates your new ESI-ID.
3. Submit your T-SAW request via fax or phone to Reliant after the 48-hour period has elapsed.
4. Reliant submits an MVI request to ERCOT.
5. CenterPoint Energy receives an MVI request from ERCOT and installs your new meter.
6. Electricity service will start within three to seven business days after CenterPoint Energy receives MVI request from ERCOT.*
7. You will receive an initial bill from Reliant.

Establish Permanent Service

1. Contact CenterPoint Energy to establish an ESI-ID. You must specify at the time of request if you require a remote read (OMR) meter.
2. Wait 48 hours while CenterPoint Energy generates your new ESI-ID.
3. Submit your permanent service request via fax or phone to Reliant after the 48-hour waiting period has elapsed.
4. Reliant submits an MVI request to ERCOT.
5. CenterPoint Energy receives an MVI request from ERCOT and installs your new meter.
6. Electricity service will start within three to seven business days after CenterPoint Energy receives MVI request from ERCOT.*
7. You will receive your initial bill from Reliant.

Discontinue Service

1. Submit your move-out (MVO) request via fax or phone to Reliant. You must specify at the time of request if facilities should be disconnected.
2. Reliant submits MVO to ERCOT.
4. CenterPoint Energy obtains a final reading from your meter for billing and disconnects facilities, if applicable.
5. Electricity service should be terminated within three to seven business days after CenterPoint Energy receives MVO request from ERCOT.*
6. You will receive your final bill from Reliant.

Homeowner Needs Permanent Service

1. Builder submits MVO request via fax or phone to Reliant. Builder is responsible for service until the MVO is complete, which could take approximately three to seven business days from the date of your MVO request.*
2. New homeowner needs to contact a retail electric provider to establish service. Existing Reliant customers should request a transfer of service.
3. Reliant submits an MVI request to ERCOT.
4. Electricity service should be transferred within three to seven business days after CenterPoint Energy receives an MVI request from ERCOT.*
5. The new homeowner will receive an initial bill, and the builder will receive a final bill for service.

* *Turnaround-time estimate is independent of construction and weather delays and is based upon estimates provided by CenterPoint Energy, ERCOT and Reliant. Estimates assume receipt of all permits by CenterPoint Energy.*

Turndown Information

If CenterPoint Energy turns down a meter installation, the MVI is suspended. After the appropriate corrections have been made, you must call the Reliant Homebuilder Hotline, 1-800-716-6543, to resubmit your MVI request. Meter installation can be expected within three to seven business days after you call Reliant to resubmit your MVI request.

Permit Information

CenterPoint Energy must receive all permit information before service will be initiated. If a permit is not in place upon the receipt of the MVI request, CenterPoint Energy will place the account "on hold" pending receipt of a permit. CenterPoint Energy must receive the required permit information within 20 business days of receipt of the MVI request or they will not dispatch the service initiation order to the field. After 20 business days, (if the permit information has not been received by CenterPoint Energy) the original MVI request will be cancelled and you must call Reliant to request a new MVI. You may also fax in your request using a new Builders Authorization Fax form.

reliant
an NRG company

Reliant Energy, "Your Builder Blueprint for Electricity Service." Accessed on June 5, 2016 at: https://www.reliant.com/en/Images/hb-centerpoint-blueprint-0716.pdf

Exhibit 1304

conEdison

Account & Billing | Services & Outages | Save Energy & Money | Our Energy Future

How long does it take to get a new service or service upgrade?

It depends on the scope of work, required permits, weather conditions, etc. Generally, if your service installation requires excavation work, you should allow up to 90 days from the time we inspect your site.

The average wait time for a new meter is approximately 10 days after we receive all required deposits and applications, and have completed our final inspection.

conEdison, "Building and Remodeling Facts." Accessed on June 5, 2017 at: https://www.coned.com/en/small-medium-size-businesses/building-project-center/faq

CASE: UE 319
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1305

Exhibits in Support
Of Opening Testimony

June 16, 2017

Exhibit 1305

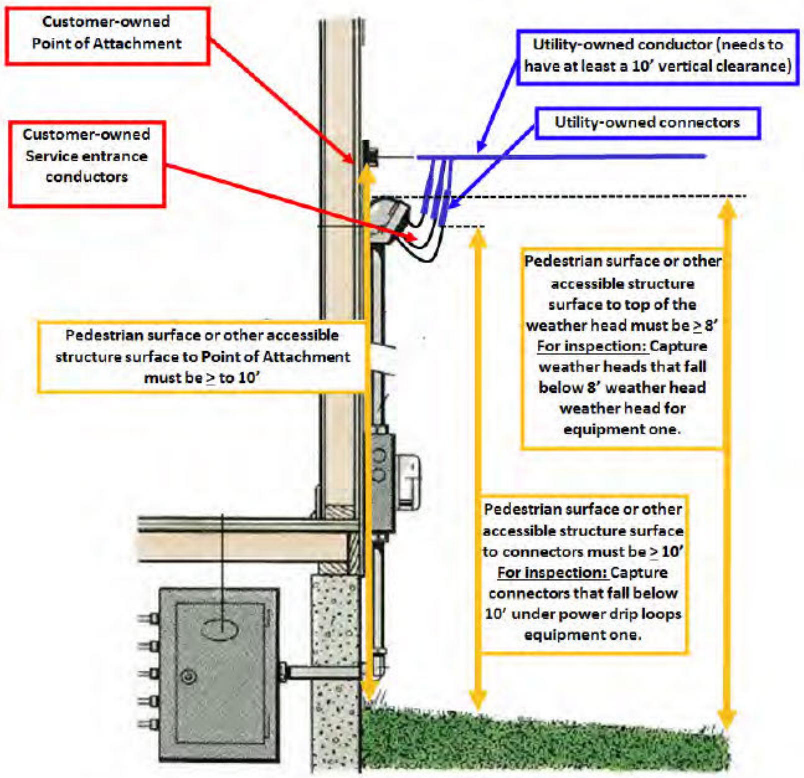

Exhibit 1305

PGE's response to Staff DR 331 is a Microsoft Excel file and is being provided digitally.

Exhibit 1305

April 10, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 329
Dated March 27, 2017

Request:

At any point from 1961 to present has PGE's electric service requirements and/or construction standards allowed installation of open wire or 230C3 services to be installed at a height below 8 feet? Please explain.

Response:

No, there has been no electric service requirement standard that has allowed a height below 8 feet prior to 1977. In the 1961 "Utility Rules and Regulations," co-authored by PP&L and PGE, a sketch showing the "typical residential overhead service" indicates the "service head must be at least 8'-6" above ground" and the "connection to service shall be *below* [the weather head or] service head." In 1977 the installation standard changed to the height of the service head at 10 feet above ground. However, even a slight change in grade to a previously installed service head could result in some portion of the service conductor drip loops and/or connectors being less than 8 feet from a pedestrian surface.

Exhibit 1305

April 10, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 321
Dated March 27, 2017

Request:

Please provide a narrative explanation of the difference between the Company's Low Clearance program (referenced on PGE/802, Nicholson-Bekkedahl/2-3), and the Company's standard NESC correction program.

Response:

To meet Division 24 safety standard requirements, PGE's Facility Inspection and Treatment to the National Electric Safety Code (NESC) Program (i.e., FITNES Program) identifies overhead service lines or facilities with less than a 10' vertical clearance over pedestrian surfaces (e.g. sidewalks, driveways, porches) as part of its annual NESC Inspection and Correction Program. Once a service line or facility has been identified as needing a clearance correction, PGE will determine whether the issue can be mitigated without action by the customer, or if additional non-utility work on the customer's side of the service is needed.

If the service line/equipment was installed prior to 1977 and the point of attachment (existing bracket, house knob) can be raised to 10' (through the installation of a new point of attachment) then this work will be addressed as part of PGE's annual NESC Inspection and Correction Program.

If the service line/equipment was installed prior to 1977 and the point of attachment cannot be raised to 10' because the building's construction will not accommodate raising it to 10', then an exception may be applied to allow a lower point of attachment. (NOTE: This exception does not apply to any point of attachment or weatherhead that does not have at least 8' of vertical clearance.)

If the point of attachment and/or the customer-owned weather head on a building that was constructed prior to 1977 has less than 8' vertical clearance and raising the point of attachment cannot be addressed by modifications to PGE-owned equipment alone (as described above), then PGE's Low Clearance Program will work with the customer and their licensed electrical contractor to make the repair. This may include replacing customer-owned weather head, modifying the building's envelop to extend the weather head, replacing the meter base, replacing the service entrance conductors, or replacing or relocating the breaker panel.

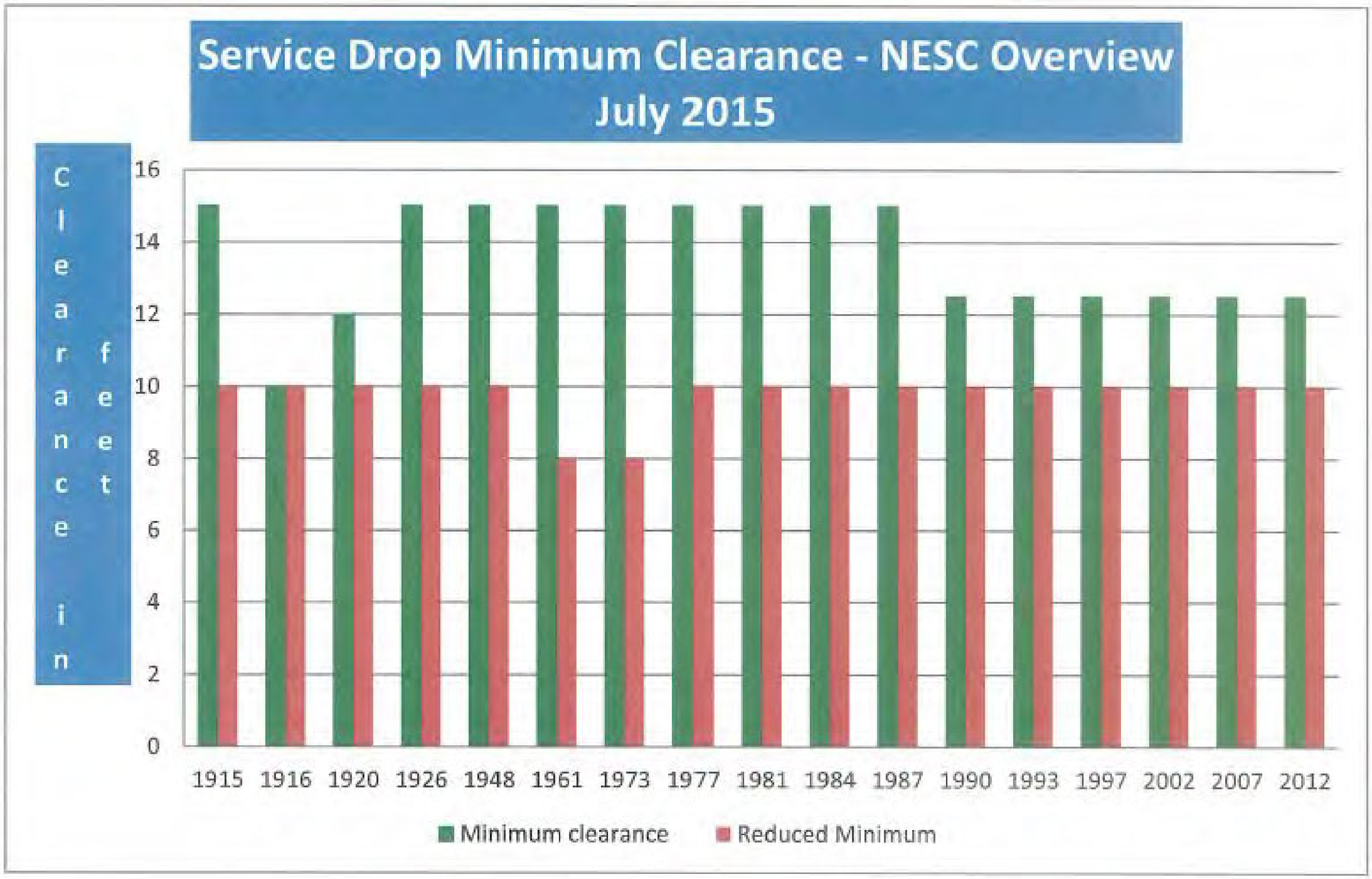

Exhibit 1305

UE 319 PGE Response to OPUC DR No. 322
Attachment 322-E
Page 5

Exhibit 1305

April 7, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 348
Dated March 27, 2017**

Request:

Is PGE aware of any other investor owned utilities that utilize a trended normal weather assumption for the purposes of preparing a GRC load forecast? If "yes," please provide each utility and GRC proceeding.

Response:

Yes, PGE is aware of general rate case (GRC) proceedings of other investor-owned utilities that were filed using the trended normal weather assumption in the load forecast. PGE is also aware of utilities filing GRCs using expert discussion of the trended normal weather method as support for implementing shorter-period, rolling-average, normal weather assumptions in their forecasts (typically moving from a 30-year rolling average to a 10-year rolling average normal weather assumption). Some examples are:

Black Hills/Colorado Gas Utility Company filed a GRC with the Colorado Public Utilities Commission in 2008 (docket 08S-290G) using the trended ("hinge-fit") normal weather assumption. A settlement was ultimately reached that used an adjusted NOAA 30-year normal.

Missouri Gas Energy filed a GRC with the Missouri Public Service Commission in 2009 (docket GR-2009-0355) using the trended normal weather assumption. PGE is not aware of the result of this docket.

Black Hills/Nebraska Gas Utility Company used discussion of the trended normal weather assumption to justify changing its normal weather assumption from a 30-year rolling average to 10-year rolling average in its GRC filed with the Nebraska Public Service Commission in 2009 (docket NG-0061). A 10-year rolling average was adopted.

Michigan Consolidated Gas Company filed a GRC with the Michigan Public Service Commission in 2010 (docket U-15985) in which it used the trended normal weather assumption in its load forecast. Although the method won the support of the administrative

law judge, the Commission ultimately ordered the adoption of a 15-year rolling average normal weather assumption rather than a 30-year rolling average.

CenterPoint Energy Resources filed GRCs in 2013 and 2015 with the Minnesota Public Utilities Commission (Dockets G-008/13-316 and G-008/GR-15-424) using discussion of the trended normal weather assumption to support use of a 10-year rolling average normal weather assumption rather than a 20-year rolling average normal weather assumption. The 10-year rolling average was adopted.

PGE understands there may be additional examples of GRC proceedings involving the trended or hinge fit normal weather assumption, such as one in Iowa, for which it was not able to identify the GRC proceeding dockets.

Exhibit 1305

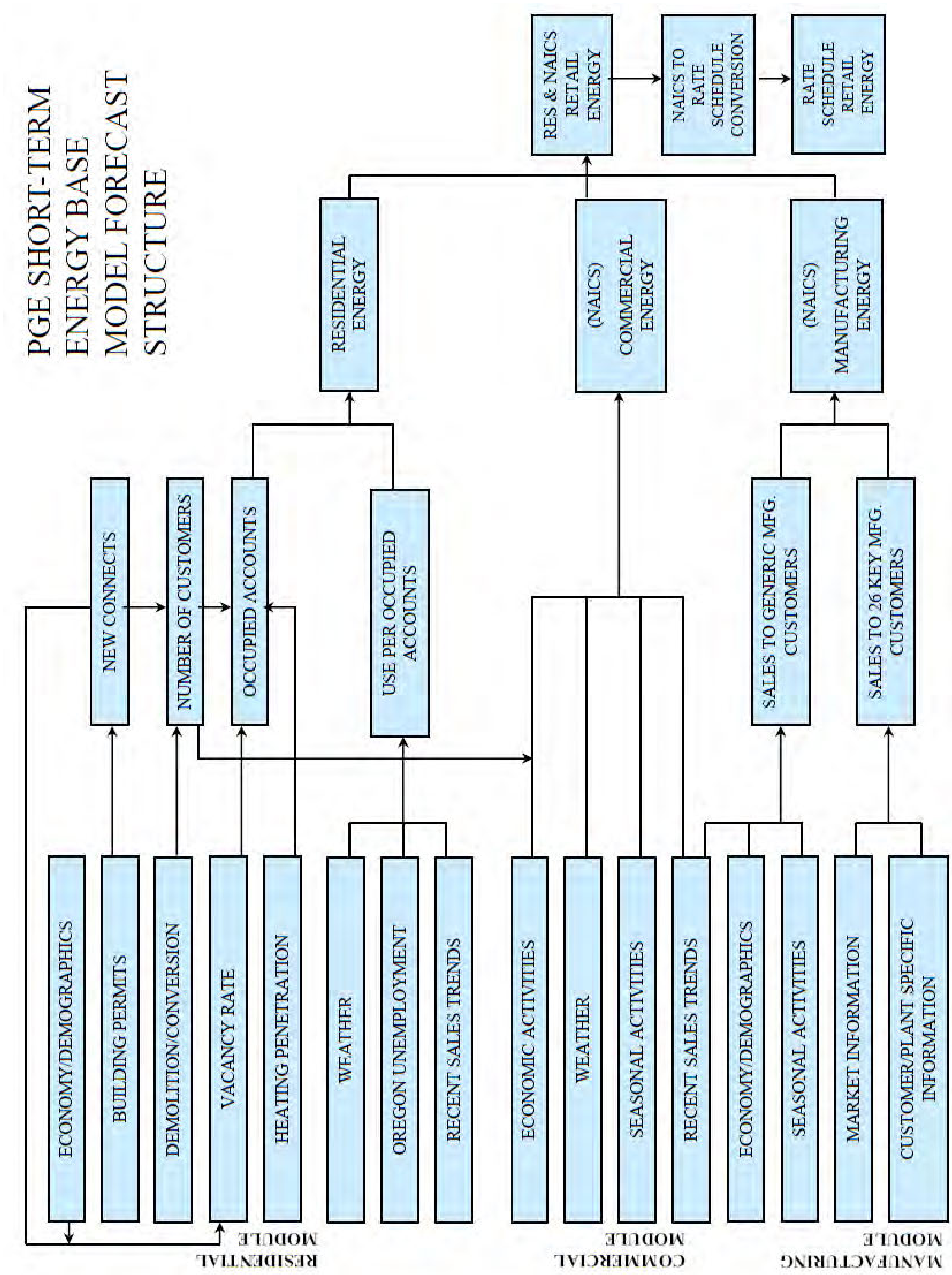

Exhibit 1305

April 11, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 396
Dated March 28, 2017

Request:

At PGE/1200/3 PGE explains how incremental energy efficiency savings from SB 838 result in explicit adjustments to the load forecast whereas energy efficiency savings from SB 1149 are assumed to be captured in the forecast model. Please provide more explanation as to this difference, why there is not a single energy efficiency savings adjustment to PGE's load forecast and any efforts to incorporate actual efficiency achievements from both SB 1149 and SB 838 back into the load forecasting models by sector (i.e., Residential, Commercial, Industrial, etc.)?

Response:

PGE's makes a single adjustment for energy efficiency savings funded by SB 838 in its load forecasting model. There is an extended history of energy efficiency savings in PGE's operating area due to a number of drivers including programmatic savings, updates to codes and standards, general market trends as appliance stock turns over with higher efficiency rating replacement and a general affinity towards conservation for many customers in PGE's service area. This trend is embedded within the historical energy deliveries data used to estimate PGE's sector level regressions. However, incremental savings, above and beyond what is embedded within the model trend need to be explicitly adjusted for in the load forecast. PGE's load forecast methodology assumes the ETO savings funded by SB 838, the more recent programmatic funding, to be incremental savings above what is embedded in the forecast trend and explicitly adjusts for these savings.

PGE is aware of several alternative methods to account for energy efficiency savings directly in regression-based forecast models being used in electric utility deliveries forecasting. A foundational premise of implementing these alternative approaches is that there is an accurate historical series available to use in modeling. In this case, a historical time series of energy savings for each of PGE's forecast groups is required. Recognizing a number of potential issues with these data, including an extended lag time which would impede PGE's ability to integrate the most recent historical data into its updates, PGE has attempted to create the required time

series data using granular, customer level, savings information provided by the ETO. Unfortunately, PGE has not found the quality of these data to be appropriate for creating time series history for each of PGE's load forecast model sectors. Some of the data quality issues include: inability to tie to total reported savings annual values (annual error of +/- 25%); customers incorrectly classified by customer segments; savings values that are annual without available seasonality; duplicate records some of which appear to be valid while others do not; inability to segment into residential housing type and heat type; and savings that are larger than total energy on an individual account. Without a reasonable historical series to include in regression analysis, PGE has been unable to move forward with modeling investigation of alternative methods.

Exhibit 1305

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 532
Dated April 24, 2017

Request:

Does PGE allow residential customers to have a kW demand in excess of 30 kW? If, "yes," please indicate the proportion of residential customers that had a demand in excess of 30 kW in 2016?

Response:

Yes, PGE's tariff allows residential customers to have demand in excess of 30 kW. PGE ran two separate queries for residential customers that met or exceeded 30 kW once or more during 2016. As a result of these two queries, PGE estimates that of the 752,388 average residential customers, as few as 0.001% and as much as 1.3% of these residential customers met or exceeded 30 kW at some point during 2016.

Exhibit 1305

May 31, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 638
Dated May 23, 2017

Request:

Does PGE believe that its commercial customers would reduce their peak demand if PGE instituted a mandatory on-peak demand charge, please explain?

Response:

PGE objects to this request on the basis of ambiguity and lack of clarity. PGE is uncertain what Staff means by "commercial customers." Subject to, and without waiving its objection, PGE responds as follows:

PGE currently has mandatory on-peak demand charges for standard service customers greater than 30 kW through Rate Schedules 83, 85, 89, and 90. Optional specialty schedules with relatively small annual consumption relative to the standard schedules such as outdoor lighting, irrigation, and Schedule 38 do not have demand charges due to their special characteristics (e. g., unmetered load, seasonal consumption, low load factors).

Schedule 32 Small Nonresidential Standard Service does not have demand charges. PGE has not performed a detailed demand charge analysis with respect to Schedule 32 that would enable it to accurately respond to Staff's inquiry above. In addition, implementation of a demand charge for the sake of peak remand reduction related to generation costs should be measured against other available alternatives such as critical peak pricing, and/or time-of-use pricing. Furthermore, implementation of demand charges for Schedule 32 would require a detailed analysis that should incorporate numerous factors including the capacity and capabilities of the current billing system and the data collection system that enables the billing system. Other factors to consider, while not exhaustive, are specified in PGE's Response to OPUC Data Request No. 637.

Exhibit 1305

May 31, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 637
Dated May 23, 2017

Request:

Please explain, does PGE believe that on-peak demand charges incentivize reductions in peak demand? See for example Schwarz (1984) at 1 which states "the peak demand charge encourages a reduction in the maximum demand."[1]

Response:

PGE objects to this request on the basis of ambiguity and lack of specificity. PGE is uncertain what is meant by "on-peak" or what functionalized costs the demand charges specified above are intended to recover. Subject to, and without waiving its objection, PGE responds as follows:

On-peak demand charges could encourage reductions in peak demand for individual customers depending on the nature of the customer's consumption patterns and how the demand charge is structured. PGE believes that peak demand reductions can also be accomplished through critical peak pricing, peak time rebates, and time-of-use pricing.

For more information regarding the implementation of demand charges, see the UE 262 PGE Exhibit 1500 testimony, pages 31-35:

http://edocs.puc.state.or.us/efdocs/UAA/ue262uaa135616.pdf

In addition see OPUC Staff testimony in Docket UE 246, Exhibit 1200, pages 12-16.

http://edocs.puc.state.or.us/efdocs/HTB/ue246htb144224.pdf

[1] Schwarz, Peter. (1984). "The Estimate Effects on Industry of Time-of-Day Demand and Energy Electricity Prices," *The Journal of Industrial Economics*, Vol. 32(4), pp. 523-539. Available at: http://www.jstor.org/stable/2098234

In general, the implementation or augmentation of demand charges should consider the diversity of demand of individual customers and across rate classes so as to avoid large immediate rate impacts within each rate class and anomalous results across the rate classes. In addition, the implementation of demand or augmentation of demand charges, if deemed desirable relative to other alternative rate structures should be accompanied by a customer education process. Other factors to consider include the time interval of demand measurement (e.g., 30 minute or 60 minute period), customer acceptance and understanding, and the impact on utility revenues.

Exhibit 1305

June 6, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 639
Dated May 23, 2017

Request:

Please explain, does PGE agree that capacity is priced below its marginal cost in PGE's Schedule 32 and Schedule 38?

Response:

PGE objects to this request on the basis of ambiguity and lack of clarity. Subject to, and without waiving its objections, PGE responds as follows:

PGE is unsure what Staff specifically means by "capacity" or which functionalized "marginal cost" Staff is referencing. Furthermore, PGE generally sets prices based on functionalized embedded costs which are allocated to the rate schedules on the basis of a marginal cost study and each rate schedule's usage and customer characteristics.

PGE believes that Staff is questioning the appropriateness of recovering the allocated demand-related costs for Schedules 32 and 38 through volumetric charges. PGE notes that the proposed prices for Schedules 32 and 38 recover the costs allocated to each of the two rate schedules without subsidy from other rate classes.

With respect to Schedule 38, PGE further notes that that this optional schedule is predominantly composed of low load factor customers whose annual consumption sums to approximately 30,200 MWh, or approximately 0.18% of 2018 projected cost-of-service consumption. Similar to the irrigation Schedules 47 and 49, and also similar to the irrigation schedules of other utilities, imposing demand and/or ratchet demand charges on these customers would have very large rate impacts. Hence, because of these potential large rate impacts, and because of other broader social policy implications such as Electric Vehicle charging, PGE believes that it is appropriate to continue to recover the allocated costs for optional Schedule 38 predominantly on a volumetric basis. Furthermore, PGE notes that should Schedule 38 customers wish to be

placed on a schedule with demand charges they may do so by requesting to be placed on Schedule 83.

With respect to Schedule 32, PGE is not necessarily opposed to exploring the implementation of distribution demand charges at some future date after PGE has completed the necessary infrastructure associated with the Customer Engagement Transformation to support such a change. The precautions specified in PGE Responses to OPUC Data Request Nos. 637 and 641 would necessarily apply.

Exhibit 1305

May 2, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 538
Dated April 24, 2017

Request:

See the table on page 3 of the Appendix of Order No. 16-292. Please provide the total costs deferred as of April 24, 2017 for each of PGE's two residential demand response pilots.

Response:

The amounts provided below are as of April 26, 2017. Note that the 2015 amounts have been adjusted downward from those included in Order No. 16-292.

	2015	2016	2017	Total
Pricing Pilot	$392,588	$749,647	$121,237	$1,263,472
DLCT Pilot	$29,076	$333,517	$68,888	$431,481
Totals	$421,664	$1,083,163	$190,125	$1,694,952

Exhibit 1305

May 2, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 539
Dated April 24, 2017

Request:

See Order No. 16-292. How long does PGE plan to run its two residential demand response pilots?

Response:

The term for the Schedule 5 Direct Load Control Pilot ends September 30, 2017. The pilot appears to be successful. Consequently, PGE plans to request to extend the pilot and increase the participation.

The term for the Schedule 6 Residential Pricing Pilot ends April 30, 2018. PGE may request to extend the pilot or use the results to inform and request to modify its residential time of use option.

Exhibit 1305

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 434
Dated April 6, 2017

Request:

In 2016, what proportion of PGE's residential customers utilized the Energy Tracker?

Response:

In 2016, PGE had 50,607 residential customers utilize Energy Tracker. Of PGE's 803,428 total residential customers, this represents approximately 6.3% of residential customers that utilize Energy Tracker. PGE presumes that "utilize" means that a unique customer, as defined in OPUC Data Request No. 433, selected an Energy Tracker link.

Exhibit 1305

April 19, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 439
Dated April 6, 2017

Request:

See PGE's response to Staff DR 271. Is PGE aware of any reasons, other than differences in billing versus metering data (including outage and non-outage communication issues), that the usage provided in the Billing Cycle feature pasted below would differ from a customer's monthly billed usage? If "yes," please explain.

Response:

Yes. Energy Tracker uses the billing cycle to determine the dates for summarizing usage. Since Energy Tracker does not have the timestamp of the billing read, the customer's billed usage could differ from the Energy Tracker summed usage if the billing read has a timestamp other than midnight.

CASE: UE 319
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1400

Opening Testimony

June 16, 2017

Q. Please state your name, occupation, and business address.

A. My name is George R. Compton. I have been employed by the Public Utility Commission of Oregon since March of 2007. I am a Senior Economist (part-time) within the Energy, Rates, Finance, and Audits Division. My business address is 201 High St. SE Ste. 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/1401.

Q. What is the purpose of your testimony?

A. I will be addressing the residential optional time-of-use (TOU) rate design.

Q. Have you prepared exhibits for your testimony?

A. Yes.

Exhibit 1402 – Sample residential TOU schedule used by a non-Oregon utility.
Exhibit 1403 – A detailed exhibit portraying the development of Staff's alternative TOU schedule.[1]
Exhibit 1404 – PGE's responses to Staff Data Request Nos. 548 and 549.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Please provide an overview of your testimony.

A. Time-of-use rates have long been favored by economists and utility regulators for two reasons: fairness is achieved by capturing in prices the cost

[1] For the convenience of the reader, two key principles behind Staff's recommended rates are also displayed in this exhibit.

distinctions that reflect time-of-use variations; and utility cost-efficiency is fostered by encouraging greater consumption during lower-cost time periods. While Portland General Electric (PGE or Company) has had smart meters and has offered TOU pricing options for several years now, customer interest in the residential TOU rate option is still miniscule: fewer than three thousand customers out of a Schedule 7 total of 772 thousand have opted for TOU rates.[2] One explanation for such a small level of interest is that a lot of customer inconvenience is required to achieve very little savings. For example, the average TOU customer has shifted almost eight percent of his usage over to the off-peak time zones, but saves only about five dollars in his average month's bill (out of a total of about $160).[3]

In this testimony, Staff proposes fairly modest TOU price reforms that will place prices on more of a cost-based footing and encourage greater off-peak usage by customers who are so inclined. In particular, Staff proposes reducing the off-peak price from $0.09125/kWh to $0.04375/kWh. That decrease would be offset almost in its entirety by an increase of $0.02981/kWh in the on-peak and mid-peak prices.

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[2] The subject of this testimony is the TOU rate sub-schedule *within* the general residential Schedule 7. That sub-schedule contains three distinct prices, labeled as on-peak, mid-peak, and off-peak. *Pilot* Schedule 6 also contains some TOU options.

[3] Exhibit Staff/1403 shows the sources and calculations, and cells J14 and J25 show, respectively, the bills calculated using the non-TOU and TOU rates.

Topic 1: The Dual Purposes of TOU Rates

Q. How are virtually all of PGE's residential kWh priced?

A. Apart from those customers on various TOU options, the first 1000 kWh of a month's usage are priced at one rate (around eleven cents per kWh); the remaining kWh are priced at a rate that is about seven-tenths of a cent higher. No distinction is made for when the electricity is consumed.

Q. Do industrial customers see rates that vary by the time of day or day of week?

A. Yes, although there is not the same level of granularity that is found in the optional residential TOU schedule. For example, no seasonal distinction is made in the industrial tariffs. And rather than distinguishing between on-peak and mid-peak periods, those periods are combined and defined simply as "on-peak."

Q. Do aggregate residential usage patterns play some role in how costs are allocated to the residential rate Schedule 7?

A. Yes, they do. In particular, generation and transmission capacity costs are allocated among customer schedules on the basis of residential customers' share of load at the time of the coincident peak of the following four months: December, January, July, and August.

Q. In addition to varying by season, do PGE's costs also vary according to the day of the week and the time of the day?

A. They certainly do. Actually, the time periods drawn by PGE for its Schedule 7 optional TOU schedule, i.e., on-peak, mid-peak, and off-peak, follow those variations quite well. For example, the truly off-peak period is defined as all twenty-four hours for Sundays and selected holidays, and from 10 p.m. to 6 a.m. the rest of the week.[4]

Q. How much do PGE's costs vary among its three designated periods?

A. As an indication of how the energy portion of its costs vary, PGE has proposed the following energy charges in its current general rate case application: on-peak – 13.121 cents/kWh; mid-peak – 7.517 cents/kWh; and off-peak – 4.375 cents/kWh.[5] Note that the on-peak rate is about three times the off-peak rate. The 7.517 cents mid-peak rate is also what PGE proposes for its residential flat rate for consumption in excess of 1000 kWh in a month.

But the rates I just listed are only the energy charge portion of PGE's volumetric residential tariff. There is also the combined Distribution and Transmission (D&T) charge, which comes to 4.75 cents/kWh. That charge is applied to all hours of the day and week even though the underlying costs vary across time.

Q. What would be wrong with charging everybody about a 12 cents/kWh flat rate for all kWh, regardless of the time-of-day/week/month?

A. Customers whose use tends more to the off-peak hours would be paying something in excess of costs, which would go to subsidizing customers

[4] For May through October the on-peak period runs from 3 p.m. to 8 p.m. Monday through Friday; and for November through April it is 6 a.m. to 10 a.m. and 5 p.m. to 8 p.m. also Monday through Friday. All-day Saturday and the remaining eleven hours on Monday through Friday are defined as mid-peak hours. On a typical, i.e., non-holiday, week the approximate share of off-peak, mid-peak, and on-peak hours are, respectively, 43%, 15% and 42%.

[5] The cited figures are from PGE's current general rate case application, Docket No. UE 319. They are very close to the rate elements in the existing tariff.

whose use tends more to the on-peak hours. TOU rates tend to match revenues with costs, thereby avoiding inter-customer cross-subsidization.

Q. Do TOU rates have a benefit other than customer fairness?

A. When TOU rates are “effective,” customers shift away from peak-period usage. The decrease in peak-period consumption enables a utility to put off costly, peak-serving capital expansions. Further, fuel costs are lower in off-peak periods, which means decreased on-peak consumption allows the utility to reduce operating costs. Effective time of use rates should result in a utility’s overall costs being lower than they otherwise would be.

Topic 2: PGE's Under-Performance Re Those Purposes

Q. In your introductory remarks you said there were fewer than three thousand residential TOU customers out of the total of 772 thousand customers on Schedule 7. You have also described some quite large gaps between on-peak, mid-peak, and off-peak energy rates. With those kinds of price differences why do you suppose there is not a greater interest in residential customers signing up for the optional TOU rates?

A. Human nature could explain a lot of it. Most people do not want to go through the inconvenience of adjusting their lifestyle to match electricity price schedules—particularly if the bill savings seem inconsequential. Fortunately that latter hurdle can be partly overcome by extending cost-causation principles to the other charges on a customer's bill.

Q. What do you have in mind?

A. Besides the energy rates there are two other kWh-volumetric rates in the residential tariff: A rather large distribution charge and a smaller transmission charge. As regards the pricing of distribution and transmission (or D&T), PGE makes no TOU distinction.[6] If, for example, the D&T charge were only applied to the on-peak and mid-peak hours, more residential customers may be inclined to subscribe to the TOU schedule in order to take advantage of the low off-peak composite rate.

[6] The very modest $5 savings noted in this testimony's introductory comments derive solely from the differential energy rates. My Exhibit Staff/1403 shows the bill savings, sources, and various computations.

Q. What is the magnitude of the D&T charge compared to PGE's residential energy charge?

A. Currently, a residential customer who uses 1000 kWh in a month will pay $68.50 for energy and $42.72 for D&T.[7]

Q. Is there a cost justification for not applying D&T charges to consumption in the off-peak period?

A. Yes, there is strong cost-justification. Transmission costs tend to be driven by coincident peak demands, which are inevitably during on-peak periods. Distribution costs are driven by schedules' non-coincident peak demands, which may occur during a mid-peak period but never in an off-peak period. The absence of off-peak distribution system distress or cost-causation is manifest in the fact that PGE's large customer Distribution Demand charge is *not* imposed against demands that occur in the off-peak period.[8]

Q. Is there an emerging customer usage development that would lead to a greater interest in TOU rates?

A. There certainly is. For customers who own electric vehicles (EVs), there is generally little inconvenience in waiting until 10 pm (when the off-peak period commences) to re-charge their vehicles. One of the main elements of PGE's

[7] For the next 1000 kWh, there would be the same $42.72 D&T revenues but the energy revenues would be elevated to $75.72. The pending PGE application would elevate the D&T amount to $47.50.

[8] *See* Schedules 83, 85, 89, or 90. The smaller, customer-centric "Facility Capacity" charge applies to the month's maximum demand, whenever it occurs.

advocacy in the EV Docket UM 1811 is to “outreach and educate” customers regarding the merits of the TOU rate schedule(s).[9]

Q. You spoke of making the TOU schedule more attractive by shifting the D&T charge entirely away from the off-peak period. Have other mechanisms been employed for encouraging off-peak consumption?

A. Some utilities have adopted demand charges as a means for reducing energy charges generally. My Exhibit Staff/1402 displays a Georgia Power example. By adopting a demand charge of $6.64 per kW, that utility seems to have eliminated the recovery of fixed generation and D&T costs through a per-kWh charge. Notably, the off-peak energy charge is *less than* one cent per kWh.

Q. Is Staff contemplating in this docket anything along what Georgia Power has achieved?

A. That is the subject of the next section of this testimony.

[9] The three primary elements of the PGE proposal are Outreach & Technical Assistance, Electric Mass Transit 2.0, and Electric Avenue Network. *See* Page 11 of “PGE Application for Transportation Electrification Programs,” Docket No. UM 1811.

Topic 3: Staff's Modest Residential TOU Correctives

Q. Before going further, please answer this: must a demand charge be introduced if the objective is to minimize the off-peak kWh charge?

A. No. The economic theoretic ideal is to have a marginal-cost-based off-peak kWh charge. Off-peak marginal costs are limited to fuel/energy costs, which means that demand, or capacity, costs are not a factor. The appropriate role of the demand charge would be to reduce on-peak and mid-peak per-kWh charges

Q. What are PGE's marginal fuel/energy costs?

A. PGE's "2016 Transportation Electrification Plan" (Docket UM 1811) shows a "Year 1 Power Purchase Price" of $0.024 per kWh.[10] The Plan indicates this price is "[b]ased on PGE net variable power cost forecast." Given the way that figure is used in the Plan's text, I interpret it as a good marginal energy cost estimate. The $0.024 figure compares with PGE's $0.04375 off-peak energy charge and the combined off-peak energy and D&T charge of $0.09125 per kWh. *This comparison suggests that PGE imposes an off-peak charge that is almost four times marginal costs!*

Q. Is it Staff's intention to recommend a purely marginal-cost-based off-peak residential TOU charge in this case?

A. No. As indicated in the title to this section of my testimony, the intentions here are modest.

[10] *See* page 90.

Q. What is the off-peak residential TOU charge that you recommend?

A. It is to stay with the PGE-proposed $0.04375 off-peak *energy* charge, but charge *nothing* for D&T during the off-peak hours. That will keep the off-peak charge to less than half of what the Company now proposes.

Q. You justify not recovering distribution costs during the off-peak hours on grounds that the residential schedule's non-coincident peak would "never [occur] in an off-peak period."[11] Is Staff concerned that enough customers might adopt TOU-favored load patterns to the degree that the schedule's non-coincident peak could actually occur during the off-peak period?

A. Yes, that is a concern, and it was the subject of two of our data requests.[12]

Q. Would you please summarize the requests and the Company's responses?

A. Staff asked if PGE was concerned regarding potential cost-causing stresses to the distribution grid that would occur off-peak owing to expanded electric vehicle recharging or whatever else might induce extraordinary off-peak loads in the context of favorable TOU pricing. The response was basically that concerns are premature, but they will be dealt with as they develop.

Q. How would you summarize Staff's position on this issue?

A. The potential of a shift in demand peak to what are currently off-peak hours is something worth paying attention to. A locus of Staff's concern is that a Level 2 electric vehicle re-charger has a maximum load that compares with the

[11] *See* page 6 of this testimony, lines 17 and 18.
[12] *See* Staff/1404; PGE Responses to Staff DR Nos. 548 and 549.

combined load of several standard household appliances.[13] Timely pricing policy adaptations that can head off problems before they occur should receive first priority.

Q. How do you propose to recover the lost revenues that would be the result of that off-peak rate reduction?

A. This is where it gets complicated. Understandably, PGE has not conducted a cost-of-service study specific to the residential TOU group, so we have to work from principles that, hopefully, are uncontestable.

Q. What are those principles?

A. The first general principle is that even if the off-peak price contains no D&T component, per se, the TOU customer should still contribute toward D&T cost recovery *and in a way that does not deny the customer's off-peak consumption*. The second general principle is that the TOU customer's obligation to support the D&T revenue requirement should not exceed the degree of off-peak support received from a representative Schedule 7 residential customer. There is no cost-causation basis for a TOU customer to have to supply any additional off-peak-based D&T revenues beyond the representative Schedule 7 customer's amount.

Q. Have you prepared an exhibit that applies those principles?

A. Yes, Exhibit Staff/1403.

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[13] Load examples: Level 2 re-charger…8 kW; Water heater…4.5 kW; Clothes dryer…3 kW; HP furnace…2.25 kW -7.5 kW.

Q. Would you please walk us through the exhibit as briefly as you can?

A. Certainly. I'll do it in numbered steps. The cell references refer to the spreadsheet of Staff/1403.

1. Note that average monthly TOU consumption is about 50% greater than the Schedule 7 average (cell G24 versus cell E5).
2. Note further the non-off-peak consumption of the TOU customer is 676 kWh compared to 501 kWh for the Schedule 7 average (cell K27 versus cell O5).
3. Since it is the non-off-peak consumption that drives D&T costs, the Schedule 7 average needs to be "ratioed-up" in order to make a direct Schedule 7-versus-TOU comparison. That is done in Rows 3 – 6 of Columns N – P. By construction, the inflated Schedule 7 average has the same amount of cost-causing non-off-peak consumption as the TOU average, i.e., 676 kWh (cell K27 and cell P5). The same ratioing factor produces the scaled up Schedule 7 off-peak consumption of 424 kWh (cell P6).
4. By the nature of a non-TOU rate structure, the 424 kWh consumption of the scaled up Schedule 7 customer supports the D&T revenue requirement through the 4.75 cent/kWh charge (cell H5 and others).
5. As a policy matter, the TOU customers should only have to support the D&T revenue requirement through the 4.75 cent/kWh charge *for the same 424 kWh* (cells K28 and K22, via cell P6) of their total of 580 kWh (cell G22).

6. To collect the same $20 off-peak D&T revenues (cell L22) and $52 D&T total (cells L23 and O23) while eliminating the off-peak D&T charge requires elevating the mid-peak and on-peak D&T charges to 7.731 cents/kWh (cells M/N 20 and 21).
7. Cell P25 shows the new monthly average TOU volumetric bill ($136) versus the $144 (cell J25) proposed in PGE's current application. The Staff's and PGE's respective savings from substituting TOU rates for standard Schedule 7 rates are 8.7% (cell P26) and 3.7% (cell J26).
8. The respective total revenues collected from the TOU customers are approximately $3.8 million (cell P24) versus $4.0 million (cell J24).

Q. Please clarify the fairness principle behind your policy recommendation to limit TOU off-peak D&T cost recovery to the same 424 kWh units that are attributable to a Schedule 7 customer with cost-causation attributes (i.e., the combined on- and mid-peak usage) that are equivalent to those of the average TOU customer.

A. Your question contains most of the answer. Since the average TOU customer and the subject Schedule 7 customer have the same D&T *cost-causation* characteristics, it would be unfair for the TOU customer to have to bear more of the D&T costs than the Schedule 7 customer.[14] That parity is achieved by (on a shadow price basis in the case of the TOU customer) charging the same price to the same number of kWh.

[14] In some instances value-of-service considerations take precedence, particularly if cost causation is ambiguous or indeterminate.

Q. Is there another broad societal basis for not wanting TOU billings to go beyond costs?

A. There is. Urban air-quality advantages of substituting electric vehicles (EV) for internal combustion vehicles provide another justification for making TOU rates more attractive in the interest of attracting greater EV ownership and use.

Q. According to your point #8 above, about $0.2 million less would be collected from the TOU customers under Staff's recommendation as compared to under the PGE application. What would happen to that $0.2 million shortfall?

A. Staff's TOU savings should be treated in an identical manner as the Company's. The PGE and Staff numerics are shown, respectively, on the lower-left and lower-right four lines of my Exhibit Staff/1403 spreadsheet. The shortfall of TOU revenues compared to what they would have been on the standard Schedule 7 rate structure is first established (cell P27, which is the difference between cell J12 and cell P24). If that shortfall is not reflected back into Schedule 7 rates then the schedule will not meet its allocated portion of the revenue requirement. The shortfall is also expressed by PGE as a "Standard Tariff Adder"[15] (cell P29) which is the shortfall divided by the total energy consumption of Schedule 7 (cell P28).[16]

[15] The term, "Standard Tariff Adder" is something of a misnomer in the sense that it is not a line-item that appears in the published tariff. Instead it is simply an amount built into average Schedule 7 rates so as to avoid the subject shortfall.
[16] Cell P30 constitutes a check that the very small standard tariff increment (cell P29) will produce the desired revenues (cell P27).

The bottom line is that, on average, all Schedule 7 customers would pay an additional $0.00003 in their volumetric charge beyond what the Company proposed (cell P29 versus cell F29) in order to make the TOU rate structure better conform with costs.[17]

Q. Does this conclude your direct testimony?

A. Yes.

[17] Cell P29 shows the gross amount as 0.05 mills/kWh. As a reminder: One mill is one one-thousandths of a dollar. So 0.05 mills translates to $0.00005. The residential tail-block rate proposed by PGE in this docket is $0.0.07517.

CASE: UE 319
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1401

Witness Qualifications Statements

June 16, 2017

WITNESS QUALIFICATION STATEMENT

NAME: George R. Compton

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Energy Rates, Finance & Audit Division

ADDRESS: 201 High Street, SE., Suite 100
Salem, OR. 97301

EDUCATION: Doctor of Philosophy, Economics (1976)
University of California, Los Angeles (UCLA) – Westwood, CA

Master of Science, Statistics (1968)
Brigham Young University (BYU) – Provo, UT

Bachelor of Science, Mathematics and Psychology (1963)
Brigham Young University – Provo, UT

EXPERIENCE: I have been employed in utility regulation since receiving my Ph.D. in 1976. My primary employer was the Division of Public Utilities, within Utah's Department of Commerce (formerly Business Regulation). I also consulted for a couple of years, early in that period. I testified frequently during my career on rate design, cost-of-service, cost-of-equity, and various policy matters affecting electric, gas, and telephone utilities. While in Utah, I also taught Economics part-time for about ten years at BYU.

Prior to my utility regulatory career, I worked in aerospace for eleven years at McDonnell Douglas (now Boeing) in Southern California.

I joined the OPUC staff soon after "retiring" to Oregon at the end of 2006. Principal cases of my involvement here have included the IRP/CO_2 Risk Guideline (UM 1302), Avista General Rate Cases (UG 181 and 284), PGE General Rate Cases (UE 197, UE 215, UE 262, and UE 283), PacifiCorp General Rate Cases (UE 210, UE 246, and UE 263), NW Natural General Rate Case (UG 221), and the Idaho Power General Rate Case (UE 233).

CASE: UE 319
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1402

Exhibit in Support
Of Opening Testimony

June 16, 2017

ELECTRIC SERVICE TARIFF:

TIME OF USE – RESIDENTIAL DEMAND SCHEDULE: "TOU-RD-3"

GEORGIA POWER
A SOUTHERN COMPANY

PAGE	EFFECTIVE DATE	REVISION	PAGE NO.
1 of 2	With Bills Rendered for the Billing Month of January, 2016	Original	2.40

AVAILABILITY:

Throughout the Company's service area from existing lines of adequate capacity.

APPLICABILITY:

For all domestic uses of a Residential Customer in a separately metered dwelling unit. A Residential customer hereunder is defined in the Company's Rules and Regulations for Electric Service.

TYPE OF SERVICE:

Single or three phase, 60 hertz, at a standard voltage.

MONTHLY RATE:

Basic Service Charge $10.00

Energy Charges:

On-Peak kWh .... 9.6052¢ per kWh
Off-Peak kWh .... 0.9896¢ per kWh

Demand Charge:

Maximum kW .... $6.64 per kW

Minimum Monthly Bill: $10.00 Basic Service Charge plus Environmental Compliance Cost Recovery, plus Nuclear Construction Cost Recovery, plus Demand Side Management Residential Schedule, plus Municipal Franchise Fee.

ENVIRONMENTAL COMPLIANCE COST RECOVERY:

The amount calculated at the above rate will be increased under the provisions of the Company's effective Environmental Compliance Cost Recovery Schedule, including any applicable adjustments.

NUCLEAR CONSTRUCTION COST RECOVERY:

The amount calculated at the above rate will be increased under the provisions of the Company's effective Nuclear Construction Cost Recovery Schedule, including any applicable adjustments.

DEMAND SIDE MANAGEMENT SCHEDULE:

The amount calculated at the above rate will be increased under the provisions of the Company's effective Demand Side Management Residential Schedule, including any applicable adjustments.

SCHEDULE: "TOU-RD-3"

PAGE	EFFECTIVE DATE	REVISION	PAGE
2 of 2	With Bills Rendered for the Billing Month of January, 2016	Original	2.40

FUEL COST RECOVERY:

The amount calculated at the above rate will be increased under the provisions of the Company's effective Fuel Cost Recovery Schedules in the manner ordered by the Georgia Public Service Commission, including any applicable adjustments.

MUNICIPAL FRANCHISE FEE:

The bill calculated under this tariff will be increased under the provisions of the Company's effective Municipal Franchise Fee Schedule, including any applicable adjustments.

SENIOR CITIZEN - LOW INCOME ASSISTANCE:

Qualifying customers certified by the Company will be eligible for a monthly bill discount of up to $18.00 monthly at their primary residence. This discount will be applied to the customer's pre-fuel monthly bill amount. To qualify, the customer must be 65 years of age or older with total household income of 200% of the federal poverty level or less per year, provided that the electric service account is individually metered and in said customer's name. There shall be no net credits nor shall there be any carry-over credits.

ON-PEAK:

The On-Peak period is defined as the hours starting at 2:00 p.m. and ending at 7:00 p.m. Monday through Friday for the calendar months of June through September (Summer Months). The above hours on days in which the following holidays are observed shall be considered Off-Peak: Independence Day and Labor Day.

OFF-PEAK:

The Off-Peak period is defined as all hours not included above in the On-Peak period including all weekends and the calendar months of October through May (Winter Months).

DETERMINATION OF BILLING DEMAND:

Maximum kW: Maximum kW shall be the highest 30-minute kW measurement during the current month.

TERM OF CONTRACT:

One (1) year. The Customer is required to remain on the TOU-RD tariff for a period of twelve (12) months from the contract date. The contract will be automatically renewed on the anniversary date of the contract for an additional year, unless terminated with 30 days' notice to the Company prior to the anniversary date. The customer may change tariffs at any time after the initial twelve (12) month term expires.

GENERAL TERMS & CONDITIONS:

The bill calculated under this tariff is subject to change in such an amount as may be approved and/or amended by the Georgia Public Service Commission under the provisions of applicable riders and other schedules.

Service hereunder is subject to the Rules and Regulations for Electric Service on file with the Georgia Public Service Commission.

CASE: UE 319
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1403

Exhibit in Support
Of Opening Testimony

June 16, 2017

Staff Exhibit 1403

is an Excel spreadsheet

(Provided in electronic format)

CASE: UE 319
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1404

Exhibit in Support
Of Opening Testimony

June 16, 2017

May 8, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 548
Dated April 27, 2017

Request:

What policies and procedures is PGE considering for addressing cost-incurring distribution grid stresses owing to the future expansion of residential electric vehicle charging loads?

Response:

PGE has not considered or introduced policies or procedures designed to offset grid stresses related to electric vehicle charging loads, as we view such policies as premature given the current market penetration of electric vehicles. Currently, there are only 8,900 electric vehicles in the Portland Metropolitan Statistical Area which represent approximately 1% of motor vehicles. The residential level 2 peak appears to occur between 10pm and 1am (see attachment 548-A, document page 23 of 43). The distribution grid impact of level 2 residential charging is highly location specific, and we are not likely to see capacity-related stress until market penetration is much higher.

However, PGE has taken a proactive stance toward guiding and reinforcing grid-beneficial charging behavior. PGE's application for transportation electrification programs (Docket No. UM 1811-as supplemented on March 15) includes a pilot to assess residential smart charging (PGE controllable level 2 chargers allow for shifting, limiting, or curtailing charging loads), as well as an outreach and education program to promote the cost savings of choosing a time-of-use rate and charging during off-peak times.

If the market penetration of electric vehicles grows over time in our service area, we may reassess the need for policies and procedures in the future.

May 8, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 549
Dated April 27, 2017

Request:

What level of a residential customer's maximum demand would PGE interpret as sufficiently distribntion-grid-stressful as to warrant a demand charge that would only have bearing when the maximum *off-peak* demand exceeded that level?

Response:

PGE has not performed a study that specifically addresses this question. Generally the degree to which a residential customer's individual maximum demand could potentially impact the local distribution grid would be highly location specific.

PGE does not believe that a residential demand charge, either during on- or off-peak hours is a preferred option. PGE believes that the appropriate price signals for residential customers can be achieved more effectively through time-of-use pricing and demand response rather than from demand charges.

CASE: UE 319
WITNESS: JEAN-PIERRE (JP) BATMALE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1500

Opening Testimony

June 16, 2017

Q. Please state your name, occupation, and business address.

A. My name is Jean-Pierre Batmale. I am a Senior Utility Analyst employed in the Energy Resources and Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/1501.

Q. What is the purpose of your testimony?

A. This testimony presents my analysis concerning Portland General Electric Company's (PGE's) energy efficiency program forecasts and funding.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/1502, PGE Response to Staff DR No. 491 and Staff DR No. 494.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1: ENERGY EFFICIENCY PROGRAMS & FUNDING

Q. What energy efficiency programs does PGE operate?

A. PGE operates several Demand Side Management programs but only one program focuses specifically on energy efficiency. Schedule 110 functions as a balancing account for this program. This schedule includes a description of PGE's energy efficiency activities: "[t]o fund Company activities associated with enabling Customers to achieve energy efficiency including, but not limited to project facilitation, technical assistance, education and assistance to support programs administered by the Energy Trust of Oregon (ETO)."

Q. What is the cost of the PGE energy efficiency program?

A. Per PGE's response to Staff DR No. 494, the Company's energy efficiency program costs approximately $840,000 annually to manage and operate.[1]

Q. How do PGE's ratepayers fund PGE's energy efficiency program?

A. Per an approved Advice Filing in 2008, Schedule 110 was established as a balancing account to fund PGE's energy efficiency program as part of the implementation of SB 838.[2] The funds that cover PGE's energy efficiency activities essentially come from the ratepayers covered by SB 838. In 2010, the maximum amount of funds PGE could use annually was $1 million.

Q. Does PGE regularly report on its energy efficiency program activities?

A. Yes. PGE provides the Commission an annual update in June.

[1] See Staff/1502, Batmale/1, PGE Response to Staff DR No. 494.
[2] Advice No. 07-25, May 12, 2008, Public Meeting Agenda, Regular Agenda Item.

Q. Does PGE utilize all of the funds that PGE collects each year for energy efficiency?

A. No. In 2015, PGE's Schedule 110 had a remaining balance of $371,090.[3] In 2016, this balance grew to $423,415.[4] Per the Company's response to Staff DR No. 494 the current account balance is approximately $465,000.[5]

Q. What are PGE's plans for the surplus balance in the Schedule 110 account?

A. Staff believes that PGE plans to utilize the surplus balance funds as a program backstop. Staff did not ask and PGE did not provide a justification for the size of the surplus. In PGE's response to Staff DR No. 491 the Company did say that after the Schedule 110 surplus grew to over $500,000 it would be open to discussing with the Commission and Energy Trust a redistribution of all of surplus funds.

Q. What are the revenue impacts of this balance?

A. PGE demonstrated that any balance associated with Schedule 110 is not included in the revenue requirement. The balance earns interest at the rate for deferred accounts.[6] There are rate impacts however. The redistribution of any surplus to Energy Trust for energy efficiency activities would reduce the amount of funds Energy Trust requests from PGE's ratepayers in Schedule

[3] 2015 FERC Form 1, page 150 of document PDF, line 32. http://investors.portlandgeneral.com/common/download/download.cfm?companyid=POR&fileid=897885&filekey=FB76F4F2-118B-4617-B8BA-5C3C0E10591C&filename=Final_2015_FERC_Form_1.pdf
[4] 2015 FERC Form 1, page 146 of document PDF, line 31. http://investors.portlandgeneral.com/common/download/download.cfm?companyid=POR&fileid=936577&filekey=E7B57B64-8B48-4EF2-ADF4-8B9EE9C542C0&filename=2016_Form_1_-_Final.pdf
[5] Staff/1502, Batmale/1, PGE Response to Staff DR No. 494.
[6] PGE Schedule 110 Energy Efficiency Customer Service, p. 2.

109 for SB 838-related activities. If PGE were to redirect its current Schedule 110 budget surplus to Energy Trust, it would be result in a one-time, 0.7% reduction in Energy Trust's funding request from Schedule 109 for 2018.[7] Residential and small business customers would benefit from this as they pay all of Schedule 109. Large customers are exempt from paying into Schedules 109 and 110 per SB 838.

Q. Are there other revenue impacts associated with SB 838 activities?

A. Yes, in addition to PGE's energy efficiency activities funded by SB 838 through Schedule 110, SB 838 also provides funding for Energy Trust's energy efficiency activities.

Energy Trust has two sources of funding for its operations: SB 1149's Public Purpose Charge (PPC) and SB 838. In 2018 Energy Trust's budget for energy efficiency will be as follows:[8]

- PPC Funding: $28.8 Million
- SB 838 Funding: $65.3 Million

While this funding does not come from rate base, it does have impacts on the amount customers pay for electricity. This is especially true as Energy Trust's SB 838 budget can fluctuate. It is tied not to revenues but to Energy Trust's Commission-approved mission to acquire all cost-effective energy efficiency annually. If Energy Trust identifies more cost-effective savings, year-over-year,

[7] Staff/1502, Batmale/1, PGE Response to Staff DR No. 494, (Explaining PGE's surplus for Schedule 110 is $465,000. Energy Trust will request approximately $65 million in SB 838 funds (Schedule 109) in 2017 and 2018.} *See* Energy Trust's approved 2017 budget, 12/16/16, "Income Statement 2016 to 2018."

[8] *See* Energy Trust Approved 2017 Budget & Action Plan.

the SB 838 charge can rise. In 2017, Energy Trust's SB 838 budget rose over 40% to $65 million due, in part, to higher savings goals.[9] The OPUC has begun a dialogue with Energy Trust to provide better forecasts and to alert PGE and other utilities when the level of SB 838 funding may change.

Q. Has PGE staffing for its energy efficiency programs grown? If so, why and how does it relate to the surplus funds in the Schedule 110 balance account?

A. Recently, yes. PGE staffing for its energy efficiency program grew from four to five FTE in 2016. This did not appear to impact program operating costs or the Schedule 110 account balance surplus. PGE's program operating costs were $840,000 in 2015 and 2016 despite adding an FTE. PGE's Schedule 110 account balance surplus appeared to grow between 2015 and 2016.

Q. What are Staff's concerns?

A. Staff is interested in ensuring that Schedule 110 funds are used effectively. It is not apparent why there is a surplus of funds in the Schedule 110 account balance or if the surplus will be used in the near future. The fully loaded cost for PGE's energy efficiency program was approximately $840,000 in 2015 and 2016. Staff assumes PGE will be spending a similar amount in 2018, as the Company did not indicate otherwise. $840,000 is below the PGE's budget cap of $1 million established by the Commission in 2010. PGE has not stated if any of their energy efficiency program activities would cause cost overruns. Further, the methodology behind carrying a program budget surplus of up to

[9] *Ibid.*

$500,000 and how any surplus Schedule 110 funds could be deployed to help PGE better accomplish its energy efficiency goals in 2018 have not been articulated.

Q. What does Staff recommend?

A. Staff has three recommendations. Staff recommends that PGE be required to:

1. Articulate its methodology for establishing, maintaining and utilizing any balance in its Schedule 110 account.
2. Establish a maximum reserve level for Schedule 110 of 15% of the allowable, annual budget, which is currently set at $1,000,000.
3. Either utilize Schedule 110 reserve funds in excess of 15% of the program's maximum budget on DSM activities in addition to marketing that also complement Energy Trust activities or transfer those reserve funds in excess of 15% the program's maximum budget to defray Energy Trust's SB 838 (Schedule 109) request for funds.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 319
WITNESS: JEAN-PIERRE (JP) BATMALE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1501

Witness Qualifications Statement

June 16, 2017

WITNESS QUALIFICATIONS STATEMENT

NAME:	Jean-Pierre Batmale
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Energy Resources and Planning Division
ADDRESS:	201 High Street SE., Suite 100 Salem, Oregon 97301
EDUCATION:	M.A. Public Policy University of California, Los Angeles (1999) B.A. History and Liberal Studies University of California, Riverside (1993)

EXPERIENCE:

I have been employed by the Oregon Public Utility since April 2016 as Senior Utility Analyst in the Utility Program's Energy Resources and Planning Division. My current responsibilities include economic analysis, policy support, and development of recommendations pertaining to energy efficiency, renewable energy and least-cost planning at Oregon's investor owned utilities and other organizations.

Prior to the Oregon Public Utility Commission I worked as the Planning Manager at the Energy Trust of Oregon for one year. I led a team of three analysts in developing Energy Trust's near- and long- term plans to achieve the organization's energy efficiency and renewable energy goals. I developed and monitored organization-wide activities and budgets reporting to senior management, the Energy Trust board, the Oregon Public Utility Commission and other stakeholders. Prior to my work in the Planning Department, for three years I was the Senior Program Manager of the Industrial Sector at Energy Trust. I led a team of five staff and seven contractors implementing a $30 million budget that acquired approximately one-third of Energy Trust's annual energy savings.

CASE: UE 319
WITNESS: JEAN-PIERRE (JP) BATMALE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1502

Exhibits in Support
Of Opening Testimony

June 16, 2017

April 25, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 491
Dated April 14, 2017

Request:

In December 2012, under Advice No. 12-22, PGE transferred $850,000 from the Schedule 110 balancing account to Energy Trust. Please provide a description of what contributed to balance account growing to nearly $942,000 in the 2018 test year, the purpose served by having an account balance nearly double the 2016 Schedule 110 activity budget, and if PGE plans to transfer the existing balance to Energy Trust in the near future as it did in 2012.

Response:

The referenced $942,000 does not represent an amount in the Schedule 110 balancing account. Instead, it represents amortization of the forecasted Schedule 110 revenue in order to move the $942,000 from revenue to the balancing account (see attachment 491-A for T-account examples). In addition, the $942,000 is not included in PGE's revenue requirement. Only the amounts highlighted in blue in PGE Exhibit 204 are included in PGE's revenue requirement. Finally, the balancing account balance as of year-end 2016 is approximately $451,000. PGE, in consultation with OPUC Staff and the Energy Trust of Oregon (ETO) will consider transferring approximately $500,000 to the ETO should the amount in the balancing account exceed $500,000.

UE 319

Attachment 491-A

Provided in Electronic Format only

T-Account Examples

April 20, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 494
Dated April 14, 2017

Request:

The average annual balance in the Schedule 110 Balancing Account would appear to be $912,250. Please calculate the benefit to ratepayers in 2018 from lowering the balance of the Schedule 110 Balancing Account to $250,000. Please explain if PGE would be supportive of capping the Balancing Account at a certain amount annually and what PGE believes that amount should be.

Response:

The question above misstates the amount of the balance in the Schedule 110 Balancing Account and seems to confuse revenues as being synonymous with balances in the Schedule 110 Balancing Account. For more information on the status of the Schedule 110 Balancing Account, please see PGE's Response to OPUC Data Request No. 490.

The current balance in the Schedule 110 Balancing Account is approximately $465,000. If PGE were to "lower" this balance to $250,000, it would either need to reduce the Schedule 110 prices to yield less in annual revenues and hence gradually reduce the Schedule 110 balancing account amount, or, alternatively, make a payment to the Energy Trust of Oregon (ETO) from the balancing account of approximately $215,000. The benefit to ratepayers could then be either slightly lower Schedule 110 prices or a one-time small increase in ETO funding.

PGE is uncertain by what Staff means by "capping the Balancing Account at a certain amount annually." Currently the amount of actual fully loaded expenses attributed to Schedule 110 program activities is expressly capped in Schedule 110 at $1,000,000 annually, a figure that PGE supports. For both 2015 and 2016, the fully loaded expenses attributable to Schedule 110 program activities were approximately $840,000.