John B. Coffman, LLC

871 Tuxedo Blvd.
(573) 424-6779 St. Louis, MO 63119 john@johncoffman.net

July 7, 2016

Via: Florida PSC Web-based Electronic Filing Portal

Ms. Carlotta Stauffer, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

RE: Docket No. 160021-EI

Ms. Stauffer:

Please find enclosed for electronic filing on behalf of AARP in the above-referenced docket the Direct Testimony and exhibits of Michael L. Brosch.

If you have any questions, please feel free to contact me.

/s/ John B. Coffman
____
John B. Coffman (Mo Bar #36591)
John B. Coffman, LLC
871 Tuxedo Blvd.
St. Louis, MO 63119-2044
Ph: (573) 424-6779
E-mail: john@johncoffman.net

Qualified Representative for AARP

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and accurate copy of the attached document has been furnished by electronic mail on this 6th day of June, 2016, to the following:

Martha Barrera
Suzanne Brownless
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
sbrownle@psc.state.fl.us
mbarrera@psc.state.fl.us

Ken Hoffman
Florida Power & Light Company
215 South Monroe Street, Suite 810
Tallahassee, FL 32301-1858
ken.hoffman@fpl.com

John T. Butler
R. Wade Litchfield
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408
john.butler@fpl.com
wade.litchfield@fpl.com

Jon C. Moyle, Jr.
118 North Gadsden Street
Tallahassee, FL 32301
jmoyle@moylelaw.com

K. Wiseman/M. Sundback/W. Rappolt
Andrews Law Firm
1350 I Street NW, Suite 1100
Washington DC20005
kwiseman@andrewskurth.com
msundback@andrewskurth.com
wrappolt@andrewskurth.com

Derrick Price Williamson
Spilman Thomas & Battle, PLLC
1100 Bent Creek Boulevard, Suite 101
Mechanicsburg, PA 17050
dwilliamson@spilmanlaw.com

Stephanie U. Roberts
Spilman Thomas & Battle, PLLC
110 Oakwood Drive, Suite 500
Winston-Salem, NC 27103
sroberts@spilmanlaw.com

Federal Executive Agencies
Thomas A. Jernigan
c/o AFCEC/JA-ULFSC
139 Barnes Drive, Suite 1
Tyndall AFB FL32403
Thomas.Jernigan.3@us.af.mil

John B. Coffman, LLC
Coffman Law Firm
871 Tuxedo Blvd.
St. Louis MO63119-2044
john@johncoffman.net

Jack McRay
AARP Florida
200 W. College Ave., #304
Tallahassee FL32301
jmcray@aarp.org

Robert Scheffel Wright/John T. LaVia, III
Gardner Law Firm
1300 Thomaswood Drive
Tallahassee FL32308
schef@gbwlegal.com
jlavia@gbwlegal.com

J.R. Kelly
Public Counsel
Patricia A. Christensen
Associate Public Counsel
Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street
Room 812
Tallahassee, FL 32399
kelly.jr@leg.state.fl.us
christensen.patty@leg.state.fl.us

/s/ John B. Coffman

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DOCKET NO. 160021-EI

DIRECT TESTIMONY OF MICHAEL BROSCH

ON BEHALF OF AARP

JULY 7, 2016

TABLE OF CONTENTS

EXHIBIT LIST

I. INTRODUCTION / SUMMARY

Q. Please state your name and business address.

A. My name is Michael L. Brosch. My business address is PO Box 481934, Kansas City, Missouri 64148-1934.

Q. By whom are you employed and in what capacity?

A. I am a principal in the firm Utilitech, Inc., a consulting firm engaged primarily in utility rate and regulation work. The firm's business and my responsibilities are related to the conduct of regulatory projects for utility regulation clients. These services include rate case reviews, cost of service analyses, jurisdictional and class cost allocations, financial studies, rate design analyses, utility reorganization analyses, the design and administration of alternative regulation mechanisms, and focused investigations related to utility operations and ratemaking issues.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of AARP, which is a non-profit membership organization that is focused on providing information and services to members over age 50.

Q. Will you summarize your educational background and professional experience in the field of utility regulation?

A. Yes. AARP Exhibit No. 1.1 summarizes my education and professional qualifications. I have testified before utility regulatory agencies in Arizona, Arkansas, California, Florida, Hawaii, Illinois, Indiana, Iowa, Kansas, Michigan, Missouri, New Mexico, Ohio, Oklahoma, Texas, Utah, Washington, and Wisconsin in regulatory proceedings involving electric, gas, telephone, water, sewer, transit, and steam utilities. A listing of my previous testimonies in utility regulatory proceedings is set forth in AARP Exhibit No. 1.2.

Q. What is the purpose of your testimony in this docket?

A. My testimony is responsive to the asserted multi-year revenue requirement and requested rate increases of Florida Power & Light Company ("FPL" or "Company") that are sponsored by various Company witnesses in their Direct Testimony, as summarized in FPL's Minimum Filing Requirement ("MFR") Schedules.[1] My testimony explains why the Company's proposed rate increase for the forecasted 2017 Test Year is seriously overstated and why the Company's further requests for an additional "subsequent year" rate increase in 2018 and for third Limited Scope Adjustment ("LSA") rate increase in 2019 should be rejected. I also address certain policy reasons why residential customer charges should not be increased.

Q. Please summarize the recommendations that are set forth in your testimony.

A. My testimony addresses several major policy issues raised by FPL's ratemaking proposals that collectively serve to seriously overstate the Company's proposed overall base rate request. These policy issues include the Company's proposed:

- Multi-year rate plan that is not supported by credible financial forecast data and entails unreasonable risk to ratepayers,
- Subsequent year 2018 rate increases that are dependent upon financial data that is highly speculative and cannot accurately predict FPL's revenue requirement that far into the future,

[1] MFR Schedule A-1 is separately presented by FPL for multiple future years, including the Projected Test Year Ended 12/31/17, a Projected Subsequent Year Ended 12/31/2018 and for the First Year Annualized Revenue Requirement associated with the Okeechobee Energy Center for a Projected Year Ended 5/31/2020. Schedule A-1 summarizes amounts pulled forward from other MFR Schedules referenced therein, for each of the three periods.

- Additional Limited Scope rate increases proposed on a piecemeal basis for the Okeechobee generation expected to be completed in 2019, with no credible showing of overall financial need,
- Excessive return on equity capital levels proposed in all three years.
- An excessive equity ratio that further overstates the claimed overall cost of capital, and
- An additional equity return "bonus" for claimed management performance that should be rejected.

I have concluded that the Company's proposed multi-year rate plan, with sequential and cumulatively massive base rate increases, has not been shown to be reasonable and should be rejected. Instead, only a single base rate change should be implemented in this Docket, based solely upon 2017 test year rate base, operating income and cost of capital findings, to the extent found to be reasonable by the Commission after analysis by the Commission Staff and other intervenors,.

The uncertainties inherent in attempting to accurately forecast electric sales volumes, capital market conditions, utility expense levels and rate base investments more than 24 months into the future, when coupled with the unavoidable management bias in developing such ratemaking forecasts, dictates that such speculative forecasts <u>not</u> be relied upon as support for large utility rate increases stretching into 2020 and beyond. The risks of FPL's proposed multi-year rate plan argue against its adoption. Instead of a multi-year approach, if changes in FPL's cost and revenue levels signal the need for additional base rate increases <u>after</u> 2017, it is my understanding that the Company can submit a future base rate case application to justify such increases.

Q. What information have you relied upon in formulating your recommendations?

A. I relied upon the Company's pre-filed testimony, exhibits and MFR Schedules in this Docket, as well as the Company's responses to data requests submitted by the Commission Staff, AARP, the Office of Public Counsel ("OPC") and other intervenors. I also rely upon my prior experience with the regulation of public utilities over the past 38 years, including significant experience with traditional test year rate cases and alternative forms of regulation of electric utilities in many different states.

II. FPL PROPOSED RATE INCREASES

Q. What is your understanding of the Company' proposed Base Rate increase in this Docket?

A. FPL witness Ms. Ousdahl states that the purpose of her testimony, "…is to support the calculation of the rate relief and appropriateness of the ratemaking adjustments FPL proposes in this proceeding."[2] She indicates that her calculations support the following three rate increases:

1. A requested 2017 Base Rate Increase of $866 million.[3]
2. A requested 2018 Subsequent Year Base Rate Increase of $262 million.[4]
3. Another 2019 Limited Scope Base Rate Increase of $209 million, for the first 12 months of operation of the Okeechobee generating unit facility.[5]

The cumulative annual increase in revenues of $1.3 billion represents an increase of more than 23 percent over jurisdictional base rate revenues at present rates in the 2017 test year.[6]

2 Direct Testimony of Kim Ousdahl, page 5.
3 Id. page 9.
4 Id. page 10.
5 Id. page 12.

Q. How would FPL's residential customers be impacted by a cumulative 23 percent increase in the Company's base rates?

A. A residential customer using 1,000 kWh would experience a monthly bill increase of $8.78 in 2017, rising to an $11.40 cumulative increase in 2018 and then $13.62 cumulatively in 2019. After all three proposed rate increases, the percentage increase in this residential customer's estimated bill would be 14.85%. When properly viewed in the context of only Base Rate revenues, FPL's cumulative proposed increase to a residential customer at 1,000 kWh would exceed 23 percent.[7] We should be mindful of the fact that FPL customers also remain exposed to potentially large additional future bill increases, when and if natural gas market prices rebound from the historically low levels now being enjoyed, because of the Company's large exposure to natural gas as a generation fuel.

Q. How do the values you recite from MFR Schedule A-2 compare to the projected customer bills set forth in FPL witness Ms. Cohen's Exhibits TCC-2?

A. Ms. Cohen shows Base charges within a typical residential customer bill rising from $54.86 at January 2016 to $70.28 in June of 2019, which represents a Base Rate increase of 28 percent.[8] However, by including an assumption of no significant increase in fuel input prices throughout the entire five year period,[9] Ms. Cohen is able to conclude, "…under FPL's rate proposal, the five-year compound annual growth rate ("CAGR") of

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6 The sum of the Company's three proposed base rate increases is $1,337 million, which is 23.3% of jurisdictional "Revenue from Sales" for the 2017 projected test year of $5,728 million in MFR Schedule C-1 at line 1, column (10).

7 See MFR Schedule A-2, line 5 for 2017, 2018 and a Projected Year Ended 5/31/2020. The $13.62 increase starting in 2019 is a 23.3% increase over Present Rates - Base Revenues of $58.39 at 1,000 kWh.

8 Exhibit TCC-2, page 1. When Base charges in the typical bill at June of 2019 of $70.28 are compared to Base charges in April of 2016 of $57.00, the percentage increase in Base charges is 23 percent within only 38 months.

9 Fuel input price assumptions embedded in Ms. Cohen's Exhibit TCC-2 are unstated, but the "Fuel" element of monthly estimated future bills is only 5 percent higher in January 2020 than in January of 2016, an assumed increase of less than 1.5% per year.

the total bill increase from January 1, 2016, through the end of the four year rate proposal on December 31, 2020, is projected to be approximately 2.8 percent."[10] Of course, Ms. Cohen and FPL cannot guarantee that fuel prices will not significantly increase throughout the next five years. Notably, this is a base rate case proceeding, so the more valid measure of rate impacts is to consider the very large increase that is proposed for <u>base</u> rates over the next three (not five) years.

Q. Why has FPL proposed a multi-year rate plan?

A. The Company's policy witness, Mr. Silagy, describes FPL's multi-year rate increase proposal in this way:

> In an effort to promote long term stability for customers, the Company and Florida's economy, FPL's request addresses rates over a multi-year period. Specifically, we are proposing a base rate adjustment in 2017, a smaller, subsequent-year adjustment in 2018, and an adjustment in mid-2019 that is limited only to recovery of the cost of the FPL Okeechobee Clean Energy Center. With the approval of these requests, there would be no general base rate increases in 2019 and 2020. While not without risks to FPL, this approach is itself a significant benefit for customers in terms of providing rate certainty, and avoiding repetitive and costly rate proceedings.
>
> In addition, this multi-year approach would allow the Company to continue focusing on ways to improve its operations and performance, better meet customer needs and expectations, and ultimately provide strong, smart infrastructure that delivers reliable, clean, affordable electricity to the Floridians and businesses we serve.

Mr. Silagy continues with a discussion in his testimony of what he calls a "History of Constructive Settlements" that are characterized as providing customers with "stability and predictability" in rates, providing FPL with "financial strength" to make necessary investments, while the settlements, "avoided additional costly and resource-intensive

[10] Direct Testimony of Tiffany Cohen, page 6.

base rate proceedings and allowed the Company's management team and employees to focus on ways to continue to find efficiencies, develop and implement innovative technologies and solutions, and improve the way in which services are delivered."

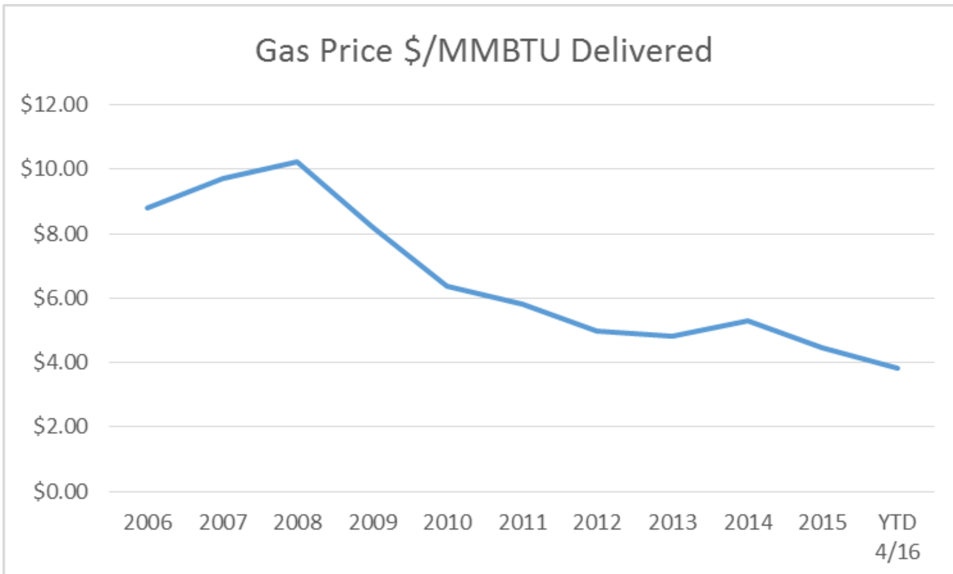
Q. Does the Company attempt to characterize its proposed 23 percent, $1.3 billion base rate increase, under the future multi-year rate plan now being proposed, as beneficial to customers?

A. Not directly. Instead, Mr. Silagy and the Company's other witnesses seem to rationalize the large proposed future base rate increases by looking backward and discussing operational and financial results under the prior rate settlement. For example, Mr. Silagy claims, "As described by FPL witness Barrett and other FPL witnesses, the 2012 Rate Settlement has proven to be of significant value for our customers. During the term of this settlement agreement, FPL has been able to continue to improve its already high level of service and operational performance. As I stated earlier, this period of stability has been one of the key benefits of a multi-year rate solution, allowing management and all employees to focus on improving service delivery for customers and realizing additional efficiencies in the Company's operations." Mr. Silagy then lists several generation modernization projects, cost reduction, emission reduction and reliability improvement initiatives and concludes, "[t]his was accomplished while keeping typical customer bills among the lowest in the state and the nation."[11]

Q. How important are the favorable trends in the cost of natural gas to the Company's argument that its rates are currently very low in comparison to other utilities?

[11] Direct Testimony of Eric Silagy, pages 9-10.

A. Gas is the primary fuel consumed by FPL to generate electricity and in 2014 natural gas represented 69 percent of the Company's overall fuel mix.[12] Fortunately, from the perspective of FPL customers, the delivered cost per MMBTU of natural gas consumed by FPL for electric generation has trended dramatically downward since 2008:



Over the same time period, FPL has increased its dependence upon natural gas as a generation fuel source, reducing fuel diversity and increasing the risk to ratepayers that higher future gas prices will amplify the higher bill impacts caused by the Company's proposed large base rate increases. If the 636 million MMBTU of natural gas that was used by FPL for generation fuel in 2015 were priced at the 83.5 cents higher average price incurred just one year earlier, in 2014, the annual cost difference to FPL and ratepayers (via the fuel adjustment) would exceed $531 million.[13]

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[12] FPL responses to Staff Interrogatory No. 140 and AARP Interrogatory No. 28.

[13] FPL's response to AARP Interrogatory No. 18 shows FPL's average delivered cost of Natural Gas in 2015 was $4.4543/MMBTU, compared to $5.2897/MMBTU in 2014, a reduction of $0.8354. When this difference is applied to 2015 annual gas volumes of 636,277,332 MMBTU, the cost savings impact is $531.5 million.

Q. FPL witness Ms. Cohen states, "Even with FPL's proposed base rate increases, FPL's projected typical bills in 2020 will be *lower* than 2006, as compared to the CPI which is projected to increase 33 percent over the same time period."[14] Mr. Silagy raises a similar argument, stating, "[a]s illustrated in Exhibit ES-2, today's typical residential bill is significantly lower than both the state and national averages and also is lower than it was ten years ago in 2006."[15] Did the favorable trend in natural gas costs since 2006 contribute to the bill impacts cited by Ms. Cohen and Mr. Silagy?

A. Yes. The gas price trends shown in the graph above contributed significantly to FPL's historically favorable bill impacts. However, when FPL was asked to quantify how the trends in typical residential bills shown in Mr. Silagy's Exhibit ES-2 would change "in order to hold constant the average 2006 average delivered price of natural gas throughout all periods," the Company claims to be unable to respond without conducting hypothetical System Production Cost Modeling of how FPL's system would have been dispatched in those prior years and asserted that "…such an analysis would have no probative value in evaluating FPL's success in controlling costs."[16]

Q. When the Commission considers FPL's proposal for much higher base rates as part of a new multi-year rate plan, should trends in the Company's overall bills historically be relied upon to find the Company's past performance acceptable?

A. No. Fuel costs are recovered through a rate adjustment mechanism because they are believed to be financially important and potentially volatile and because such costs are determined by market conditions that are largely beyond the control of utility

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14 Direct Testimony of Tiffany Cohen, page 27.
15 Direct Testimony of Eric Silagy, page 7.
16 FPL response to AARP Interrogatory No. 17.

management. FPL should receive no "credit" for historically favorable trends in market natural gas prices. The Commission should also remain aware of the substantial risk of future gas price volatility that the fuel adjustment mechanism effectively shifts to ratepayers. If higher fuel adjustment clause charges are needed in the future because gas prices return to historical average levels, those fuel charges will become additive to the base rate increases now being sought by FPL, at which time the Company will have less interest in touting trends in customers' typical bills.

Q. Should FPL's proposed new multi-year rate Base Rate plan be adopted by the Commission in order to achieve rate stability and predictability for customers?

A. No. FPL has not proven the need for any Base rate relief beyond the 2017 test year. The massive uncertainties associated with projecting costs and revenues more than 24 months into the future argue against accepting such projections as a basis for higher charges to ratepayers in 2018 and 2019 as proposed by FPL.[17] Any new multi-year rate plan must be supported by robust financial projections that employ reasonably balanced input assumptions to demonstrate that ratepayers are better off under the plan than without such pre-approved rate levels in all applicable future years. Even with such projections in hand, the massive uncertainties involved in accurately predicting the utility's future operational and financial environment multiple years into the future involves risks that are likely insurmountable while injecting considerable controversy over which party's assumptions about the more distant future should be adopted.

[17] The Company's filing submitted in March of 2016 depends upon projected results through 2020 to commit to no additional base rate changes until after 2020, a period extending more than 57 months past the filing date. The proposed 2018 subsequent year rate changes involve forecasted operations through December of 2018, which extends 33 months beyond the submission of the Company's rate filing package.

III. MULTI-YEAR RATE PLANS

Q. Mr. Silagy referenced rate stability as a claimed benefit of the Company's multi-year proposal. Are stable rates being proposed by FPL?

A. No. The Company's proposal is for a cumulative base rate increase of about $1.3 billion, that would increase overall base revenues by about 23 percent if approved by the Commission.[18] In addition to the proposed base rate increases, FPL ratepayers are exposed to potentially large future fuel adjustment charge increases if future natural gas fuel prices increase toward historical average levels. This is not a recipe for rate "stability" for FPL customers.

Q. Mr. Silagy also claims a benefit of multi-year rate plans is an improved ability for management to "focus" upon the business to improve service quality and efficiency. Is it necessary for electric rates to be established for multiple future years in a single rate case in order for utility management to remain focused upon the need to improve reliability, maximize operational efficiency, comply with emission regulations and control costs?

A. Of course not. Utility management is responsible for these core utility business responsibilities without regard to how electric rates are established. Hypothetically, if electric rates were tightly constrained for multiple years within a rate plan that was carefully designed to impose "stretch" financial goals upon the utility, it could be argued that efficiency incentives are improved. However, during FPL's current rate plan that expires after 2016, the Base Rate levels and other additional rate relief approved in Order No. PSC-13-0023-S-EI clearly did not involve "stretch" goals. Instead, forecasted

[18] See footnote 6.

non-fuel O&M expenses and capital costs were seriously overstated by FPL in its filing in Docket No. 120015, relative to actual costs in subsequent years. Additionally, FPL's large incremental investments in modernization of the Cape Canaveral, Riviera Beach and Port Everglades plants were not completed by FPL without incremental rate relief through three additional generation base rate adjustment ("GBRA") rate increases, all at additional expense to ratepayers.[19]

Q. On the other hand, was the multi-year rate plan established in Docket No. 120015-EI extremely beneficial to FPL and its shareholders?

A. Yes. The Company's rate plan that expires at the end of 2016 has clearly been very beneficial to FPL and to NextEra shareholders. The expiring rate plan has produced sustained, exceptionally strong financial performance in every year 2013 through 2016 for the Company and its shareholders. According to MFR Schedule D-7, FPL has experienced persistently strong earned returns on average book equity and steadily increasing interest coverage ratios, which have contributed to reported growth in earnings per share and the market value of the common shares of NextEra Energy, Inc.

Q. If we look further back into history, have FPL's shareholders experienced <u>any</u> periods of inadequate returns in the past decade, under the Commission's rate orders or the multi-year rate plans that are discussed by FPL witnesses?

A. No. One would expect that previously approved FPL rate plans that had carefully balanced the interests of shareholders and ratepayers would produce fluctuating return levels both above and below authorized levels, because of changing business conditions, weather variations and the normal risks of business operations imposing costs that occasionally exceed rate case forecasted levels. However, rather than fluctuations in

[19] See Order No. PSC-13-0023-S-EI, page 5.

such results, FPL's actual return on average common equity for the past decade (years 2006 through 2015) has exceeded 10.0% in every one of the last ten years, including each of the recession years starting in late 2008. Most recently, FPL earned 11.5% returns on equity in both years 2014 and 2015.[20]

Q. Have FPL/NextEra shareholders taken any large risks or incurred potentially unrecovered costs in order to earn the historically large returns that have been reported?

A. No. The financial rewards achieved by FPL and NextEra shareholders over the past decade have come largely at the expense of ratepayers, who continued to pay ever higher Base Rate charges to support FPL's financial results while also absorbing a growing liability for larger future rate base rates as the Company booked amortizations of depreciation reserve balances to further improve FPL recorded earnings.[21]

Q. Has the multi-year rate plan that was established in Docket No. 120015-EI produced base rate stability FPL ratepayers?

A. No. While customers' <u>overall</u> bills have not increased much, due mostly to the declining market prices of natural gas fuel used by FPL, there has not been Base Rate price stability since the Company's last rate case was completed. In fact, FPL customers are actually now paying significantly higher base rates than were approved by the Commission in Order PSC-13-0023-S-EI. Because this Docket is concerned with the adjustment of base rates, the proper focus of regulatory attention should be strictly upon

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[20] FPL Response to AARP Interrogatory No. 10.

[21] In response to AARP Interrogatory No. 71, FPL provided calculations showing how return on equity has been increased historically each of the prior years 2010 through 2015, through the recording of negative depreciation expenses that increased earnings in those years, but will increase future rate base and required depreciation recoveries from ratepayers in future years.

base rates, without the mixing of recently favorable historical fuel price trends that distract attention from the Company's persistently growing Base rates.

Q. How much have FPL's residential base rates increased under the current rate plan?

A. Using Residential Service under rate schedule RS-1 as an example, the Commission approved Customer and Energy Base Rate levels four years ago that resulted in a total Base Rate charge to a typical residential customer using 1,000 kWh of $49.61.[22] Comparing the Company's filed MFR Schedule A-2 "Bill Under Present Rates" calculation for Rate Schedule RS-1 in 2016 reveals that the same 1,000 kWh residential customer is now paying $58.44 in Base Rate charges to FPL. Base Rate charges to residential customers, at this usage level, have already increased about 18 percent in the past four years, an annual rate well above general inflation,[23] before any attention is given to the large prospective increases in Base Rates that are now being proposed by FPL.

Q. Are there any conceptual benefits of adopting a multi-year rate plan?

A. Yes. The primary benefit of a multi-year rate plan is the expanded regulatory lag incentive that is provided to utility management to find new ways to reduce costs, with the prospect of retaining any resulting savings for shareholders for an extended period between rate cases. Then, eventually, any incremental achieved level of savings could be captured for the benefit of ratepayers within the forecasts used in future rate cases. A

[22] See Order PSC-13-0023-S-EI, Attachment A, page 31, RS-1 Tariff, Fortieth Revised Sheet No. 8.201, the approved Customer Charge was $7.00 and approved Base Energy Charges were 4.261 cents per kWh for the first 1,000 kWh per month and 5.261 cents thereafter.

[23] For example, FPL witness Ms. Morley states in Direct Testimony at pages 51-52, "The overall CPI is forecasted to increase at a compound annual rate of 2.5% between 2015 and 2020, the same rate experienced on average since the 1990s and up modestly from the 2.1% compound annual rate averaged between 2010 and 2014."

secondary and much smaller potential benefit is the avoidance of rate case expenses by reducing the frequency of base rate cases. However, these benefits are only realized by customers if rate case forecasts accurately and completely reflect only the reasonable cost required to be incurred to provide utility services over the extended period between rate cases, while anticipating and including a productivity offset that requires management to reduce costs in order to earn targeted return levels.

Q. What are the risks that are created when utility rates are established for more than one future forecasted year?

A. The primary risk associated with any test year using forecasted operational and financial data is that the forecast will be wrong. That risk is amplified as one moves further away from known, present factual circumstances toward ever more distant future forecasted periods. The dependence upon management judgment in developing forecasts, where management has unique knowledge of its facilities and relevant cost drivers, coupled with the financial incentive utility management has to pessimistically forecast relatively higher costs and lower revenues when setting utility rates (and future revenues and profits) contributes substantially to this risk. Only genuinely inept utility management would neglect to allow for all reasonably foreseeable cost increases throughout the forecasting period, while cautiously quantifying its ability to find new operational efficiencies and uncertain future cost savings.

Consider, for instance, the challenges in attempting to accurately predict the interest rate levels that will be demanded by financial markets in 2017 and then again in 2018, in 2019 and in 2020.[24] Market interest rates represent one of the many forecasting

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[24] FPL's rate plan is offered with a commitment to not seek additional general base rate relief in 2019 and 2020 according to Mr. Silagy's Direct Testimony at page 7.

assumption inputs needed to accurately determine FPL revenue requirements for multiple future years. Similar future knowledge and accurate forecast assumptions are needed for many other key inputs across the entire utility business enterprise, including major cost drivers such as:

- workforce staffing and labor hour requirements in each department,
- wage rate assumptions for each employee group,
- employee benefit cost rates for pensions, insurance and all other plans,
- employee incentive compensation terms and performance assumptions,
- non-labor expense inflation/escalation rates applicable to all vendors,
- generating unit outage schedules and work scope estimates,
- vegetation management work scope and scheduling,
- insurance premium charges and damage claims estimates,
- customer growth and electric sales demand trends across all classes,
- capital spending programs, projects, priorities, and contingencies,
- property, income and other tax rate and determinants, and
- affiliate cost allocations and charge/credit amounts.

The scope and complexity of forecasting, including recitation of some of these key assumptions, is revealed in the Company's MFR Schedule F-8 and Exhibit REB-2, which is a 35 page Planning and Budgeting Process Guideline document sponsored by FPL witness Mr. Barrett.

Q. Is it possible to accurately predict all the elements of test year revenue requirements?

A. No. Even with best efforts and assuming no bias, future conditions are often ultimately not very predictable and unexpected changes in operating conditions, weather, market conditions, laws and regulations will occur that will impact the costs treated as recoverable through Base Rates in ways that are not predictable. The challenge is therefore to carefully examine rate case forecasts with a healthy appreciation of the many challenges to accurate forecasting as well as the profit incentives that tend to encourage utility management to overstate forecasted costs and understate future sales and revenue growth that will be available to offset higher costs.

Q. Does the difficulty in predicting future electric sales/revenues, expense and capitalized (Rate Base) cost levels preclude the use of a forecasted test year?

A. No. But dependence upon forecasted data adds considerable complexity to the ratemaking process and should demand much more involvement in rate case audits and the careful testing of forecasting assumptions that drive what level of forecasted costs ratepayers must support. A single future test year can be reasonably tested against recent historical facts and amounts, because changes are more predictable in the near future than the more distant future. For example FPL knows how many employees in each department are required to operate and maintain all the facilities and automated systems that exist <u>today</u>. However, the staffing levels needed next year, in terms of employee headcounts and labor hours, is somewhat less certain, due to continuous changes in installed facilities, new technologies being deployed, weather impacts, variable customer demands, changes in laws and regulations, opportunities for outsourcing work to contractors and the potential for business mergers and reorganizations. In more distant forecast years two or three, much less is known or knowable about the variables impacting the quantity of required labor. At the same time the unit prices for employee wage increases and benefit costs become less certain in more distant future forecasts. The same types of uncertainty exist and expand in more distant future periods when forecasting interest rates, inflation rates, productivity rates, sales volumes and the many other components of a rate case test year forecast. Judgment is involved throughout the forecasting process, since future outcomes are uncertain.

Q. Does the required judgment in constructing forecasts introduce an unavoidable bias when forecasted test years are used to set utility rates that define and limit the utility's future earnings opportunity?

A. Of course. From the utility's perspective, there is a strong incentive to pessimistically forecast future utility cost increases and sales growth, so as to reduce the risk of unfavorable variances caused when actual costs exceed the levels of forecasted cost used in setting rates. From the ratepayers' perspective, utility management has a tremendous information advantage from which to develop rate case forecasts that employ pessimistic assumptions and inputs, so as to optimize rate levels and reduce the risk of lower future earnings if future actual costs exceed rate case forecasted levels.

Q. Are you aware of any published study that address the problems with bias and information asymmetry that are associated with utility forecasts that are used to set rates?

A. Yes. On August 13, 2013, the National Regulatory Research Institute ("NRRI") published a report titled, Future Test Years: Challenges Posted for State Utility Commissions. NRRI is the research arm of the National Association of Regulatory Utility Commissioners ("NARUC"). A full copy of this report is included in AARP Exhibit 1.3. The Executive Summary of this report defines future test year ("FTY") and historical test year ("HTY") approaches and states:

> The reader might ask why a commission should rely on anything other than an FTY, since good ratemaking requires that new rates reflect the utility's costs and sales, at least over the first several months that they are in effect. Ratemaking, after all, is prospective, and an FTY matches the test year with the effective period of new rates. <u>Although in theory this argument seems indisputable, it ignores the reality that forecasts are susceptible to error and some costs and sales elements are inherently difficult to predict. Another factor, as this paper stresses, is that utilities would have incentives to present biased forecasts that are not always easy for commission staff and interveners to uncover</u>. A commission would be presumptuous to assume that forecasted costs and sales are more accurate than modified HTY data accounting for "known and measurable" changes. In fact, many commissions have taken this view, which seems sensible and in line with their mandate to set "just and reasonable" rates.
>
> In sum, an environment of rising average cost does not constitute a sufficient condition for the use of an FTY. Supporters of an FTY give this false impression, which ignores the reality of utility forecasts being susceptible to bias and inherent error. Information asymmetry, which is an acute problem in public utility regulation, makes it difficult for commissions to evaluate a utility's forecasts in terms of their accuracy and objectivity.[25]

This report also discusses three major areas of concern when using future test year forecasts:

- **Why would a utility be more inclined to overstate costs than to understate costs?** The utility expects the commission to lower its cost forecasts, so it would tend to initially file inflated costs. There is little payback for a utility that hedges on the low side. The likelihood of the utility's actual costs being higher would increase, thus jeopardizing its rate of return and penalizing shareholders.

- **How serious is this problem?** It depends on the ability of a utility to get away with reporting inflated costs. For example, the utility might ask for recovery of costs in a rate case no matter how frivolous or unlikely they are. It has little to lose if the commission catches it (except for the credibility of future forecasts); if the commission approves the cost, the utility recovers "phantom" or imprudent costs. The result is that the utility's customers are paying excessively for utility service.

- **How can a commission detect overstating of costs?** It can observe any systematic bias in past forecasts. For example, it may detect constant overforecasting of a certain cost item for a number of years. The only way for a

[25] <u>Future Test Years: Challenges Posted for State Utility Commissions</u>; August 13, 2013, National Regulatory Research Institute ("NRRI"), Executive Summary at iv.

> commission to uncover inflated costs, although admittedly imperfect, is to do a thorough review of the assumptions, methodologies and other factors underlying the forecasts. This activity requires a commission staff with adequate resources and skills. It also subtracts time from other crucial rate-case matters that could lead to ill-informed decisions.[26]

The bias inherent in test year rate case forecasts is undeniable and appears to have negatively affected FPL ratepayers when the Company's forecasts were relied upon in prior rate case proceedings.

Q. Do you know if FPL has presented significantly overstated forecasts of test year O&M expenses, in its most recent prior rate case filings before this Commission, when such forecasts are compared to actual expenses that were incurred in the same test year?

A. Yes. FPL's forecasted non-fuel O&M expenses were significantly overstated in each of the last two rate case cycles involving 2010 and 2013 test years. To the extent these forecasts were relied upon in setting rates,[27] the Company's ratepayers were disadvantaged by the unreasonably pessimistic forecasts that became the basis of the approved revenue requirements.

In the Company's most recent rate filing in Docket No. 120015-EI, the forecasted 2013 test year non-fuel O&M expenses included in FPL's filing, after removing recoverable fuel costs and making all other required ratemaking adjustments, was $1.558 billion. The comparable adjusted actual 2013 non-fuel O&M expenses

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[26] Id., page 24, footnotes omitted.

[27] Approved rates in Docket No. 120015-EI were based upon a settlement that was approved by the Commission. If any of FPL's forecasted costs were disallowed in Docket No. 080677-EI, such disallowances may have impacted some of the variance amounts that were actually charged to ratepayers.

totaled $1.428 billion, a favorable variance of about $130 million or more than eight percent of the forecasted expenses included in FPL's rate filing.[28]

In the Company's earlier rate case filing involving a forecasted 2010 test year in Docket No. 080677-EI, FPL again seriously overstated expected test year O&M expenses. The forecasted 2010 test year non-fuel O&M expenses included in FPL's filing, after removing recoverable fuel costs and making all other required ratemaking adjustments, was $1.504 billion. The comparable adjusted actual 2010 non-fuel O&M expenses totaled $1.407 billion, a favorable variance of about $97 million or more than six percent of the forecasted expenses included in FPL's rate filing.[29]

Q. Would adoption of multiple test years, as now proposed by FPL, amplify the risk to ratepayers that the Company's forecasted costs could again be overstated in more than one future period?

A. Yes. FPL management has a strong financial incentive and a fiduciary responsibility to shareholders to maximize the utility's earnings opportunity provided under Commission-approved rates. Because of this reality, more extensive regulatory dependence upon management-prepared forecasts for multiple future periods increases the exposure of ratepayers to these incentives and responsibilities.

Q. Do any of FPL's witnesses acknowledge the added risk caused by use of multiple future forecasted test years?

A. Yes, but only from the perspective of shareholders, for whom FPL has a duty to maximize profits. Mr. Silagy describes the rate increases proposed within the Company's multi-year rate plan and then states, "With the approval of these requests,

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28 FPL response to AARP Interrogatory No. 68, Attachment 1.
29 FPL response to AARP Interrogatory No. 67, Attachment 1.

there would be no general base rate increases in 2019 and 2020. While not without risks to FPL, this approach is itself a significant benefit for customers in terms of providing rate certainty, and avoiding repetitive and costly rate proceedings." Mr. Dewhurst takes this concern for shareholders one step further, indicating the Company's proposed ROE level was increased due to the risks to shareholders of the multi-year rate plan:

> It is my judgment that an ROE of 11 percent would adequately reflect FPL's risk profile, including the attendant risk of the Company's proposed multi-year rate case stay-out, as discussed by FPL witness Hevert in his assessment of FPL's risk profile and the appropriateness of his recommended ROE. During this extended period of time, FPL and its investors will have significant exposure to the forecasted rising interest rate environment, and terms of access to capital could change unexpectedly, with more likelihood of unfavorable than favorable change. The Federal Reserve's December 2015 decision to increase short-term interest rates from near-zero levels for the first time in seven years is a signal of the central bank's shifting stance on monetary policy; however, there is substantial uncertainty around possible future actions. From an investor's perspective, FPL is foregoing the possibility of seeking rate relief over this four-year period in the face of substantial uncertainty. This risk is appropriately reflected in the recommended 11 percent ROE.[30]

Of course, there is no compelling need to impose these added risks upon either shareholder or ratepayers. The better answer is to simply avoid the problems created by attempting to set reasonable rates for multiple future years.

Q. What analysis has the Company produced to show that its rate plan will produce reasonable results for both shareholders and ratepayers through the year 2020, when the Company's plan would terminate?

A. The Company's filing includes no financial forecast data or analysis beyond the 2018 subsequent year to show expected financial results under proposed rates. However, it seems obvious to me that FPL's long term projections of future

30 Direct Testimony of Moray Dewhurst, page 26.

electric sales/revenues and costs to provide service, through at least future year 2020, must have convinced management that shareholders would be better off under the proposed multi-year Base rate plan than without it. It is far less certain that ratepayers would be advantaged by this FPL-derived rate plan, for all the reasons explained in my testimony. The disadvantages of a multi-year approach would be magnified if FPL were awarded an excessive 11 percent authorized equity return (11.5 percent with Mr. Dewhurst's proposed performance bonus) that is said to be needed <u>because of</u> the Company's proposed multi-year rate plan.

Q. How has FPL achieved comfort with its proposed multi-year plan for Base Rates, given the uncertainties involved in accurately predicting the future and the risks created by such long-term rate planning?

A. This is not clear from the Company's filed materials. From my experience, I expect that multiple scenarios of long-term financial forecasts for FPL's operations have been developed to test the adequacy of the proposed rates in the FPL rate plan against different levels of assumed electric load growth, capital expenditure plans, market interest rate assumptions and expense inflation scenarios. Only in this way could management be sure that its fiduciary duties to shareholders are upheld and that the financial risks to the Company caused by the multi-year rate plan are acceptable. However, no long-term financial projections of this type have been included in the Company's prefiled evidence to show whether the FPL-proposed multiple Base Rate increases stretching into 2020 are adequate but not excessive in <u>each</u> proposed future year.

When AARP asked if the Company has prepared long-term financial forecasts that were prepared to evaluate future financial performance under varying assumptions, (such as varying energy sales levels, different capital investment scenarios, alternative staffing and labor scenarios, inflation rate environments, interest rate expectations and other changeable input assumptions) the Company responded, "No" and answered "N/A" when asked for a descriptive listing of such forecasts.[31]

Q. Is this a credible response?

A. No. The more credible response was provided to NextEra's investors in the most recent earnings release on the Company's web site.[32] When asked about NextEra Energy, Inc.'s First Quarter 2016 Release and the Projected Adjusted Earnings per Share range stated therein, the Company admitted that:

> NextEra Energy, Inc. must consider a wide variety of risk factors with respect to FPL and its other direct and indirect subsidiaries to provide a consolidated range of earnings to investors. For example, NextEra Energy must consider a range of factors that could affect its forecast: the national and state economics, the credit and financing market, potential changes in capital expenditure estimates, potential changes in construction schedules of capital expenditure projects, O&M fluctuations, future prices of fuel and estimated days for nuclear outages – among others. Because of the many factors that can affect an earnings estimate, and the difficulty in modeling all possible outcomes, NextEra Energy provides investors with a wide potential range of earnings.[33]

All of these variables and risk factors clearly contribute uncertainty to FPL's forecast, a major business segment within NextEra Energy, and cannot be ignored when evaluating any multi-year rate plan. However, it is not convenient for FPL to admit that these types of uncertainties exist when discussing rate case forecasts, because there can be only one approved rate case forecast scenario upon which the

[31] FPL responses to AARP Interrogatory Nos. 2 and 3.
[32] Available at: http://www.investor.nexteraenergy.com/phoenix.zhtml?c=88486&p=EarningsRelease
[33] FPL response to AARP Interrogatory No. 9.

Commission ultimately determines approved rate levels. Ultimately, after several efforts to solicit various long term financial forecast scenarios that were produced by NextEra for different purposes, the Company has repeatedly referred only to its MFR's for FPL's rate case financial forecast.[34] This must be the only long term financial forecast scenario the Company wants to share with the Commission.

Q. Are there significant risks to ratepayers if the Company's recommended multi-year rate plan is approved?

A. Yes. Ratepayers are exposed to not only the risks of dependence upon the FPL-prepared forecast of the revenue requirement in the 2017 test year, but also the added uncertainties and greater risks associated with the more distant forecasts of sales/revenues, expenses and rate base for the proposed 2018 subsequent year. To make matters worse, for 2019 no consideration is given by FPL in its filing to whether the Company's overall revenue requirements in 2019 may be higher or lower due to changes in inflation, interest rates, productivity or other economic circumstances. Instead, FPL asks that single-issue rate increase be approved in 2019 solely to account for the incremental costs at completion of the Okeechobee generation project.

When asked for each iteration of the financial forecasts evaluating sensitivities to alternative future sales growth, inflation, interest rates, capital investment and other changed assumptions that may impact FPL's overall revenue requirements in 2019, the Company responded with a single Confidential document containing FPL's "high-level base scenario" of projected

[34] See FPL responses to AARP Interrogatory Nos. 2, 3, 5, 7, 8 and 9.

financial results and with no alternative scenarios or sensitivities to account for the large uncertainties impacting forecasted years 2019 and beyond.[35]

Q. Several FPL witnesses claim that superior management performance has allowed the Company to reduce O&M costs historically. FPL witness Mr. Barrett references "Project Momentum" as the "main catalyst that has contributed to FPL's tremendous success in lowering its operating costs since the last base rate case."[36] Do the Company's rate case forecasts of O&M expense underlying the asserted revenue requirement in 2017 or 2018 include any assumed new future productivity gains?

A. No. According to the Company's response to AARP Interrogatory No. 56:

> Except for the Project Momentum process, there are no new productivity improvement programs/initiatives expected to be undertaken in 2017, 2018 and subsequent years.
>
> The momentum 4 process, to be executed in 2016, which would produce incremental savings in 2017 and 2018, has not been completed. Forecasting costs and savings for the Momentum processes that have not yet been completed is difficult as there is no way to know in advance what productivity-improvement ideas will be generated. Moreover, the results of past Momentum processes do not necessarily provide an accurate prediction of what the future processes will be able to achieve, as the opportunities for productivity gains have been more difficult to attain and have diminished with each subsequent Momentum process, Due to these difficulties, FPL management does not forecast productivity gains associated with a Momentum process prior to its execution.

While the Company's 2017 and 2018 forecasts are said to include the continued results of prior years' Momentum processes already executed in 2013 through

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[35] FPL response to AARP Interrogatory No. 5, referencing Office of Public Counsel Interrogatory No. 3, Confidential Attachment 1.

[36] Direct Testimony of Robert Barrett, page 37.

2015, when asked to quantify forecasted costs savings from any incremental, new productivity measures included in such forecasts, the Company's response simply stated, "not applicable."[37] This is an alarming admission from a Company that is forecasting future costs that drive $1.3 billion in proposed base rate increases. If the FPL costs driving higher base rates are increasing at the levels being projected by the Company in 2017 and beyond, this is no time for management to stop performing and to simply assume no ability to incrementally reduce future costs through new productivity initiatives.

Q. Has the Commission previously rejected an FPL-proposed multi-year rate plan under similar circumstances that exist today?

A. Yes. In the Company's last litigated base rate case, Docket No. 080677-EI, the Commission's Order No. PSC-IO-0153-FOF-EI issued March 17, 2010 stated a policy preference against "back-to-back" rate increases and then rejected the subsequent test year 2011 proposed base rate increase that was proposed by FPL in that Docket, stating:

> We believe that back-to-back rate increases should be allowed only in extraordinary circumstances. Historically, we have used the test year concept for setting rates. Under this concept, the test year is deemed to be representative of the future, and used to set rates that will allow the utility the opportunity to earn a rate of return within an allowed range. If the test year is truly representative of the future, then the utility should earn a return within the allowed range for at least the first 12 months of new rates.[38]

The Commission also rejected FPL's arguments that ratepayers would benefit by avoiding a separate rate proceeding sometime in 2010 for rates that would be effective in 2011, noting that, "FPL witness Barrett admitted that FPL did not perform a cost-benefit analysis to examine whether the costs of a rate case

[37] FPL response to AARP Interrogatory No. 56, part (d).
[38] Order No. PSC-IO-0153-FOF-EI issued March 17, 2010 in Docket No. 080677-EI, page 9.

outweighed savings that could result from reexamining changing costs.” Expanding upon this message, the Order stated:

> The subsequent increase requested in this case is based on a second projected test year of 2011 and is in fact a second full rate case filing. FPL claims that this second case is necessary "to address the deterioration in earnings that will take place during 2010." However, it is important to note here that filing two general rate cases with back-to-back projected test years deprives us and deprives the Company's ratepayers of the benefit of an additional twelve months of actual economic data and operating history of the Company. This additional data could be used to validate whether an additional increase is truly necessary and whether the second test year is really representative of the future.
>
> The Company's ratepayers deserve a full investigation into the cause of FPL's claimed deterioration of its earnings. Two general rate increases that are barely twelve months apart justify the time and expense of a second separate proceeding. Two back-to-back general rate increases are especially of concern when one considers that the need for base rate increases has already been reduced for FPL due to the effect of the cost recovery clauses. Cost recovery clauses provide for approximately 61 percent of FPL's revenue and reduce the risk of underrecovery of a substantial portion of FPL's operating costs. The recovery of costs through the clauses should limit the need and frequency of full rate cases for FPL.
>
> States that make use of a projected test year, like Florida, typically only attempt to look one year into the future. FPL is asking us to look far beyond the horizon, into 2011, and raise consumers' rates not only in 2010 based on a 2010 projected test year, but to raise consumers rates again in 2011 based on speculative and untested projections for a 2011 subsequent projected test year. These test years were developed in 2008. As one reaches farther into the future, predictions and projections of future economic conditions become less certain and more subject to the vagaries of changing variables. This is particularly true given that for 2010, FPL projected results based upon the assumption of a "down economy," and for 2011 projected results based upon a "down economy just beginning to recover."
>
> Because of unpredictable changes in the economy, it is certainly possible that FPL's perceived need for a 2011 base rate increase could be offset by changes in sales growth, billing determinants, additional Stimulus Bill of the American Recovery and Reinvestment Act of 2009 (Stimulus Bill) benefits, and other cost-decreasing measures. At a time when Florida's ratepayers have been hit hard by the downturn in the economy, it makes sense to wait and see if a subsequent rate case is justified. FPL's claim that it will need a rate increase in 2011 simply is too speculative, and is hereby rejected.[39]

[39] *Id.* at 9-10.

Q. Do the same concerns that caused the Commission to reject FPL's proposed Subsequent Test Year in Docket No. 080677-EI persist today?

A. Yes. FPL has not proven that, 1) ratepayers are better off under its proposed multi-year rate plan, 2) that any savings from avoidance of a next rate case are sufficient to offset the risks of using speculative second year forecast data, 3) that changing economic conditions would not justify a careful, formal review of future revenue requirements or, that 4) FPL ratepayers don't deserve a full investigation into 2018 revenue requirements with "the benefit of an additional twelve months of actual economic data and operating history of the Company" as was demanded by the Commission in this prior Docket.

Q. Did the Commission also reject FPL's proposed Generation Base Rate Adjustment ("GBRA") mechanism in Order No. PSC-IO-0153-FOF-EI?

A. Yes. The Commission properly recognized that generating unit investments can be reasonably considered within traditional rate case filings, where costs and revenues can be reviewed "as a whole" rather than on a piecemeal basis, to determine whether rate relief is actually needed at the time of completion of such new investments:

> According to FPL, we should approve continuation of the GBRA because it is "reasonable, cost-based and sends the appropriate price signals to customers." While the term "cost-based" may accurately describe the GBRA, a rate case proceeding provides more of an opportunity to rigorously review costs and earnings as a whole. Regarding the price signals, we agree that implementation of the GBRA may link reductions in fuel costs to increases in base rates that may occur as a new plant is put in service. However, a traditional base rate proceeding could also be timed (based on the Company's request) to coincide with the in-service date of a new plant, thus achieving the same result. FPL witness Barrett testified that it is possible for the Company to structure the timing of a rate request associated with a new plant so that both the plant's costs and its fuel savings benefits are received by the customer at the same time. FPL witness Pimentel stated that "the reason that we're requesting the GBRA, first and foremost, is as we build generation that's been approved by this Commission in need determinations, we're trying to match the customer savings and fuel efficiency with the actual capital that we are

> putting into the business." This goal could be achieved within the process of a traditional rate case.
>
> Another of FPL's arguments for the GBRA mechanism was that it has the potential to avoid the need for a rate case. It is not possible for us or interested parties to examine projected costs at the same level of detail during a need determination proceeding as we would be able to do in a traditional rate case proceeding. A need determination examines costs only in comparison to alternative sources of generation. It does not allow for a review of the full scope of costs and earnings, as a rate case does. FPL witness Barrett acknowledged that the GBRA mechanism would be a limited-scope proceeding focused only on the GBRA, and intervenors would not be able to raise other cost issues in such a proceeding. SFHHA witness Kollen also argued against the GBRA because FPL would have the ability to impose a base rate increase for new generation and transmission projects without consideration of other revenues and costs. OPC witness Brown explained that if the GBRA is approved and the economy subsequently recovers, FPL's shareholders may earn greater returns that could be sufficient to cover the cost of new generating units without increasing base rates. According to OPC, having a GBRA mechanism in place would mean FPL would have less incentive to control overall costs. Witness Brown also pointed out that under the GBRA, FPL would essentially be "imposing a surcharge on customers' bills to cover the costs associated with a single component of its overall costs of providing service," and we would not have the ability to evaluate whether FPL's existing base rates were sufficient to cover some or all of the costs.[40]

These circumstances noted by the Commission in FPL’s last litigated rate case, that caused rejection of GBRA recovery of generating unit costs in isolation, all pertain to the Company’s proposed third year 2019 so-called Limited Scope Adjustment rate increase and dictate its rejection.

Q. Would a GBRA rate increase for the revenue requirement arising from only completion of the Okeechobee generation project send cost-based and appropriate price signals to customers?

A. Probably not. There has been no showing by FPL that the Company’s overall cost of service in 2019, if measured using normal “single” test year forecasting procedures and the best current factual information that is available two years from now in mid-2018,

[40] *Id.*, at 14-15.

would be equal to the piecemeal revenue requirement of only the new generation investment in isolation. The most appropriate price signals to customers would be driven by an updated measurement of the Company's <u>overall</u> cost to provide utility services in 2019, rather than inherently unreliable estimates prepared by FPL today of its expected 2018 subsequent year revenue requirement, increased by only the costs of the Okeechobee investments on a piecemeal basis in 2019.

Q. Could a base rate proceeding be timed by FPL to provide timely recovery at completion of the Okeechobee project?

A. Yes. It is my understanding that FPL is not constrained in its ability to file base rate increase applications in the future, using a test year that could provide for recovery of the change in revenue requirement caused by commercial operation of the Okeechobee generating facility. Of course, by pursuing cost recovery within a general rate case, the Company would be forced to update its sales and revenue forecasts, reflect current capital market conditions and account for other changes in revenue requirements that would be included the test year analysis undertaken at that time.

Q. Has FPL forecasted changes in sales and revenues in 2019 and 2020 that would provide additional funding that could help to offset the Okeechobee facility revenue requirement?

A. Yes. FPL witness Ms. Morley has projected that the Company's retail billed sales will be 108.5 million MWH in 2019. This represents an increase of 0.5 percent over 2018 forecasted sales of 107.9 million MWH. Then, in 2020, total billed sales are expected to grow another 1.0 percent to 109.6 million MWH.[41] The Company's retail rates provide a contribution to fixed costs within energy charges that are expected to increase with

[41] FPL Exhibit RM-3, page 1.

MWH sales in these future years, providing revenues to support overall cost increases that may be encountered by FPL after the 2018 subsequent year that is proposed. Ms. Morley also indicates that, "…annual customer growth is also expected to average 1.5% between 2015 and 2020"[42] which will contribute to the aforementioned MWH growth that is projected and will also yield additional customer charge revenues to help offset the Company's Okeechobee fixed costs and any other changes in revenue requirements after 2018. The uncertainty associated with sales forecasts, particularly multiple years into the future, makes it very difficult to know the amounts of any base rate increases that could actually be needed by FPL in 2019 or 2020. As noted above, if FPL's overall costs that do not pass through existing rate adjustment mechanisms grow more quickly than base revenues, the Company is able to timely file a base rate increase petition to prove its need for incremental rate relief, using the best current information available at that time.

Q. Does the Company's proposed 2019 Limited Scope Adjustment rate increase at completion of the Okeechobee project include any accounting for the continued growth in customers, sales and revenues that the Company has reflected in Ms. Morley's forecasts?

A. No. In fact, the Company has not accounted for any changes in its revenues or costs after 2018, other than accounting for the expected direct costs that are attributable solely to the newly completed Okeechobee project as a proposed piecemeal, single-issue rate increase to customers.

Q. Is it possible for revenue growth or cost reduction efforts to offset the costs of the completed Okeechobee project in the years 2019 and 2020?

[42] Direct Testimony of Rosemary Morley, page 17.

A. Of course. As an example, Mr. Silagy states, "…a key factor in the ability of our Company to avoid the need for a base rate increase since 2013 has been our aggressive focus on controlling these O&M costs. As FPL witness Barrett describes, despite general inflation-related increases and customer growth that are projected to add nearly $145 million to our non-fuel operating costs, we estimate that our non-fuel base O&M expense will actually be *lower* in 2017 than it was in 2013."[43] Assuming the Company may be able to further reduce its O&M expenses after 2018, in keeping with its touted historical performance levels, any new O&M savings could help to offset the increased costs of completing the Okeechobee project.

Q. Could other major changes in business conditions impact FPL's revenue requirement after 2018, beyond the direct impacts of the Okeechobee project?

A. Yes. Other structural changes to the business environment could impact FPL's future cost of service after 2018 that are not presently known and cannot be considered at this time, even though such changes may offset some of the expected Okeechobee project costs. These include the possibility of:

- NextEra mergers or acquisitions, beyond the pending Hawaiian Electric transaction, that could more broadly spread shared corporate administrative costs that are now born largely by FPL and its ratepayers,
- Changes in corporate tax laws or regulations,
- Refinancing of long term debt at lower cost rates, depending upon future capital market conditions.[44]

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[43] Direct Testimony of Eric Silagy, page 24.

[44] As an historical example, in September 2015, FPL repurchased $400 million of its debt in a transaction that resulted in savings to the Company and its customers, according to FPL's response to AARP Interrogatory

- Expanded deployment of technologies that reduce operational costs.
- Additional distribution and transmission hardening investments that reduce service restoration costs after storm events.[45]
- Continued productivity initiatives, of the types described in FPL testimony.

The point is not that these beneficial changes will fully offset rising costs, but rather that one cannot dismiss the fact that unforeseen future events may have a material impact upon FPL's actual revenue requirement in 2019 and beyond. The Company's proposed limited scope rate increase for only the Okeechobee project costs has assumed away such possibilities, proposing to ignore them in favor of piecemeal, single-issue ratemaking for only selected Okeechobee cost increases in 2019. If Okeechobee costs were instead considered within the context of an overall base rate proceeding, other changes in costs and revenues would not be ignored.

Q. You have referred in prior testimony to "piecemeal, single-issue ratemaking." Why should utility rates generally not be changed to account for only known changes in isolated types of costs?

A. As suggested in my prior testimony and in the Commission's rate order in the Company's last litigated rate case, a general rate case proceeding provides more of an opportunity to rigorously review costs and earnings as a whole. This holistic analysis is very important to the determination of just and reasonable overall rate levels that consider both favorable and unfavorable changes to the utility's forecasted revenues,

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No. 72 and POD No. 47. The Company's Treasury Department is responsible for monitoring all outstanding debt to determine whether opportunities to improve the overall funding profile exist.

[45] FPL's pending 2016-2018 Storm Hardening Plan Petition states at page 9, paragraph 20, "FPL has estimated that, over an analytical study period of 30 years, the net present value of Restoration Cost Savings per mile of hardened feeder would be approximately 45 percent to 70 percent of the cost to harden that mile of feeder for future major storm frequencies in the range of once every three to five years. Of course, it is possible that FPL will face major storms more frequently than that, as it did in the 2004-2005 hurricane seasons. If that were the case, then the net present value of Restoration Cost Savings likely would exceed the hardening costs."

expenses and earnings levels. If the utility or any other party were allowed to "pick and choose" only certain costs or revenues in isolation to adjust utility rates, the Commission can expect attempts at gaming of the regulatory framework to occur, simply because of the amounts of revenue and earnings that can be impacted by such gaming. The utility would likely propose rate changes for only increasing costs, like FPL's proposed Okeechobee limited scope adjustment, while a consumer intervenor might recommend full decoupling of utility sales and revenues for a persistently growing utility like FPL. Setting rates on a piecemeal basis invites such gaming and should be avoided to the maximum extent possible.

Q. Are there limited instances where rate adjustment mechanisms or deferral accounting for specific utility costs should be afforded extraordinary treatment outside of base rate cases?

A. Yes. Most states have adopted a form of fuel/energy cost adjustment mechanism that changes rate levels to ensure recovery of the large costs of fuel and purchased energy that can be volatile because of changing market conditions and that are largely beyond the control of utility management. Similarly, it is not uncommon after major storm events for utility regulators to allow the deferral of recovery of incremental storm restoration expenses, recognizing that utility management has little control over such events and that rapid service restoration should be encouraged without imposing a financial penalty to the utility's earnings. Some electric and gas utilities have revenue decoupling mechanisms to encourage utility support of customer energy efficiency and conservation initiatives while protecting utility earnings from deterioration due to declining sales. I understand that FPL has a broadly inclusive fuel adjustment mechanism and also benefits from a storm restoration cost recovery mechanism, but does not employ sales/revenue decoupling.[46]

As a matter of broader policy, rate tracking mechanisms for electric utilities should be limited to only those cost or revenue changes that are so large and volatile and beyond the control of utility management that not providing tracking would introduce unacceptable earnings volatility and risk to the utility, reducing its access to capital on reasonable terms. Completion of FPL's Okeechobee project does not meet any of these criteria.

Q. FPL argues that a multi-year rate plan is beneficial to customers by offering "regulatory economy" and avoiding the cost of additional base rate proceedings.[47] How does the cost savings from the potential avoidance of rate case expenses compare to the risk or adopting FPL's proposed multi-year rate plan?

A. There really is no comparison. The Company's estimated rate case expenses for the presentation and defense of its multi-year $1.3 billion increase proposal is $4.9 million. FPL witness Ms. Ousdahl sponsors this amount, stating:

> FPL is requesting a four-year amortization period for estimated, incremental rate case expenses associated with this case totaling $4.9 million. In addition, FPL is requesting that the unamortized balance be included in rate base in the 2017 Test Year and 2018 Subsequent Year in order to avoid an implicit disallowance of reasonable and necessary costs. The fact that FPL is requesting a 2018 SYA and the 2019 Okeechobee LSA as part of one proceeding reduces the amount of rate case expenses we would otherwise incur for multiple back-to-back rate cases.[48]

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[46] FPL benefits from cost recovery clause treatment of Fuel and Purchased Capacity costs, Environment costs, Energy Conservation costs, Nuclear costs and a Storm Surcharge that provide for recovery of changing cost levels outside of base rates. See FPL response to AARP Interrogatory No. 69.

[47] Direct Testimony of Robert Barrett, pages 11-12.

[48] Direct Testimony of Kim Ousdahl, page 21.

As a percentage of the proposed overall rate increase, rate case expenses contribute less than half of one percent to the Company's proposed cumulative rate increase.[49] With this in mind, even a very slight improvement in the accuracy of the annual FPL revenue requirement that is ultimately approved by the Commission is well worth incurring the necessary rate case expenses. Even if FPL required annual rate cases to fully recover a more accurately determined revenue requirement in each of the years 2017, 2018 and 2019, which is unlikely for the reasons described in my testimony, $4.9 million in costs <u>each</u> year would likely be a very small portion of any resulting rate increase. For a utility the size of FPL, rate case expense is a small price for ratepayers to reimburse in order to avoid being burdened with excessive and unproven rate increases under multi-year rate plans based upon highly uncertain forecasts.

Q. Please summarize your testimony with respect to the Company's proposed multi-year rate plan.

A. Rate case forecasts involve considerable uncertainty and judgment. In a single forecasted test year, utility management has a tremendous incentive and ample opportunity to pessimistically forecast higher future costs and few offsets for assumed new productivity gains, while proposing conservative estimates of future revenue growth. Including multiple future forecast years in support of a multi-year rate plan, as suggested by FPL, amplifies this uncertainty and judgment to levels that are unacceptable. <u>I recommend that FPL's proposed multi-year rate plan be rejected by the Commission because of the excessive risks involved and the lack of demonstrated benefits to ratepayers from bearing such risks</u>. In the event FPL can actually prove up any need for rate relief in periods after 2017, it should file future base rates cases when

[49] $4.9 million / $1,337 million = 0.37%

needed to allow the Commission to holistically consider new facts and circumstances at that time.

IV. RETURN ON EQUITY

Q. What is the Company's proposed return on equity ("ROE") for ratemaking purposes?

A. FPL witness Mr. Hevert concludes, "[b]ased on the quantitative and qualitative analyses discussed throughout my Direct Testimony and the Company's risk profile, I conclude that an ROE of 11.00 percent is a reasonable estimate of FPL's Cost of Equity."[50] FPL witness Mr. Dewhurst offers his supporting opinion, stating, "It is my judgment that an ROE of 11 percent would adequately reflect FPL's risk profile, including the attendant risk of the Company's proposed multi-year rate case stay-out, as discussed by FPL witness Hevert in his assessment of FPL's risk profile and the appropriateness of his recommended ROE."[51] However, the Company is actually proposing to charge ratepayers more than FPL's asserted cost of equity capital. According to Mr. Dewhurst, "FPL is asking the Commission to increase the authorized ROE established in this case by 50 bps, both to reflect what FPL has already accomplished in its efforts to deliver superior value to its customers and as an incentive to promote further efforts to improve the customer value proposition."[52]

Q. Have you prepared any independent analysis of the cost of equity capital that should be authorized by the Commission for FPL?

50 Direct Testimony of Robert Hevert, pages 4-5.
51 Direct Testimony of Moray Dewhurst, page 26.
52 Id. page 27.

A. No. However, I believe the information presented in this section of my testimony is supportive of Commission approval of an ROE for FPL that is significantly lower than the authorized ROE levels approved in recent FPL rate orders. Capital market conditions remain very favorable, with Federal Reserve policies remaining quite accomodative, which has caused regulators across the country to systematically reduce allowed returns for regulated electric utilities.

Q What ROE was approved by the Commission in the Company's last litigated base rate case proceeding?

A In FPL Docket No. 080677 that employed a projected 2010 test year, the Commission approved an authorized ROE of 10.0 percent.[53]

Q What ROE was negotiated by the signatory parties in settlement of the Company's 2013 test year rate case in Docket No. 120015-EI and approved by the Commission in its Order?

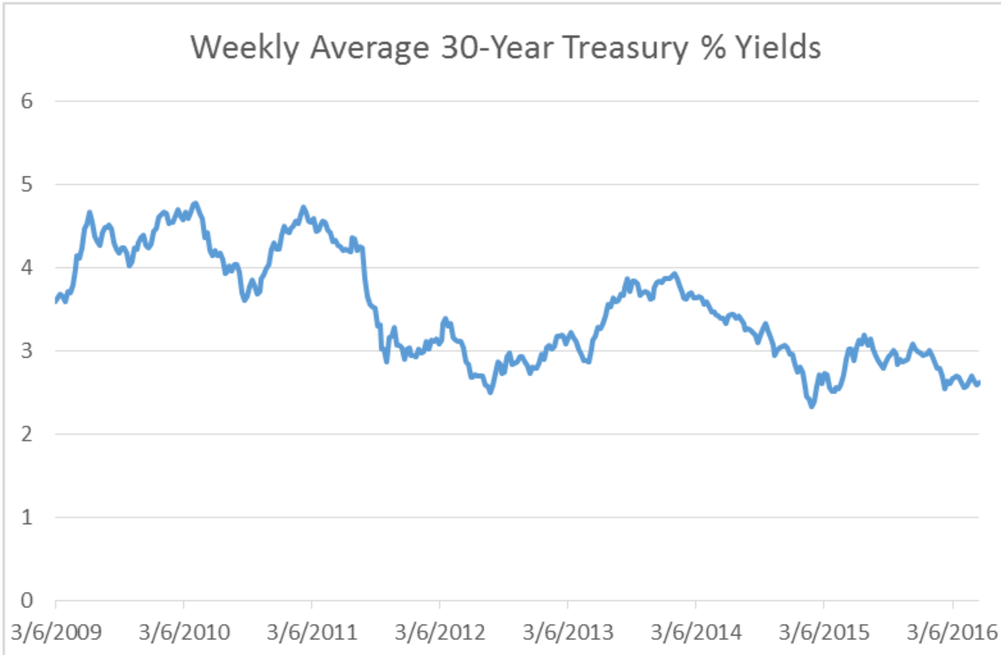
A In FPL Docket No. 120015-EI, the settling parties agreed to an authorized ROE of 10.5 percent that was approved by the Commission.[54]

Q What has happened to market interest rates, as measured by 30-year U S Treasury bond yields, since the 2010 and 2013 projected test years that were most recently employed to determine the Company's cost of equity and overall revenue requirement?

A Long term risk free rates of return, as indicated by the yield on 30-year treasury bonds, are significantly lower in 2016 than the average of such yields in 2010 or in 2013, as

[53] Order No. PSC-10-0153-FOF-EI, page 132 and Schedule 2. The authorized ROE was unchanged in Order No. PSC-11-0089-S-EI issued February 1, 2011 in Docket No. 080677-EI.
[54] Order No. PSC-13-00230S-EI, page 5 and Attachment A, page 2.

illustrated in the following chart containing data from March of 2009 through May of 2016:[55]



The settlement ROE adopted in Docket No. 120015-EI for the 2013 test year was part of a negotiated package of ratemaking provisions. Therefore, the agreed-upon authorized ROE of 10.5% may not have been directly tied to any particular party's analysis of the cost of equity. However, with regard to the earlier Commission-approved ROE in FPL's last litigated test year 2010 rate case, it is obvious that current risk free capital cost rates are much lower today than when the Commission last received evidence regarding capital costs in Docket No. 080677-EI and determined the Company's cost of equity.[56]

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[55] Information downloaded at federalreserve.gov/releases/h15 as weekly "Treasury constant maturities 30-year" as weekly (Friday) information. For the week ended July 1, 2016, the 30-year treasury yield was 2.28%.

[56] Order No. PSC-10-0153-FOF-EI issued March 17, 2010. At pages 3 and 4, the Order states that FPL's Petition that initiated the proceeding was filed on March 18, 2009 and that the Technical Hearing was held in Tallahassee on August 24-28 and 31, 2009, September 2-5, 16 and 17, 2009 and October 21-23, 2009.

Q. Does the Company's cost of capital witness, Mr. Hevert, rely upon 30-year treasury yield data within his Bond Yield Plus Risk Premium analysis, as an indicator of the risk free cost of capital?

A. Yes. Mr. Hevert states, "First, because utility assets represent long-duration investments, I relied on estimates of the 30-year Treasury yield as the risk-free rate component of the CAPM analysis." However, the "estimates" referenced by Mr. Hevert are his future estimates at 4.00 percent in 2017 to 4.80 percent in 2020, which are much higher than recent actual 30-Year treasury yields of well less than 3.0 percent.[57]

Q. Are you aware of any regulatory commission that has relied solely upon published 30-year treasury yields to determine the cost of capital for major electric utilities?

A. Yes. In Illinois, the two largest electric utilities, Commonwealth Edison Company and Ameren Illinois Companies, have opted into a major capital expansion program enabled by legislation referred to as Electric Infrastructure Modernization Act ("EIMA"). Annual formula-based rate adjustments are prescribed under EIMA, with an updated ROE each year based upon the average 30-year treasury yield for the prior twelve month period, plus 580 basis points (5.80 percent). In the pending cases filed by both utilities, this calculation yields an allowed return on equity of 8.64 percent, which is the sum of average monthly market yield for 30-year Treasury Securities in 2015 of 2.84%, plus 5.80% as the statutory "spread" above the risk free rate of return.

Q. Have FPL ratepayers benefited from the lower cost of capital in U.S. capital markets under the Company's past settlements and rate orders?

57 Direct Testimony of Robert Hevert, page 20. See also Table 3 at page 26 and FPL's response to Staff Interrogatory No. 245.

A Unfortunately, no they have not. The approved 10 percent ROE level in the last litigated FPL rate case has proven to be excessive, compared to subsequent favorable trends in the risk free cost of capital in public financial markets. Since late 2009 when the Commission last ruled upon cost of equity evidence in a litigated FPL rate case, the average risk free cost of capital has declined from well above 4 percent to well below 3 percent, a decline of more than 100 basis points. The approved ROE level in the settlement agreed upon in Docket No. 120015-EI was even more excessive, given the continuing downward trend in capital costs that has persisted in recent years.

Q. Have regulators in other states reduced the allowed ROE levels of electric utilities to recognize favorable trends in capital market conditions?

A. Yes. The comparable average ROE levels authorized for electric utilities throughout the rest of the United States in the past several years has declined, as illustrated at page 1 of the Edison Electric Institute ("EEI") Rate Case Summary – Q1 2016 Financial Update report that I have attached as AARP Exhibit 1.4 to my testimony. This report reveals the generally declining trend in average authorized ROE levels in rate orders that were issued since 2009, with the average authorized ROE across the Country below 10.0 percent in eight out of the last twelve quarters reported.[58] Further amplifying the excessive authorized ROE requested by FPL is the Company's extremely high equity ratio included within the ratemaking capital structure, that further burdens FPL ratepayers with excessive capital costs.

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[58] See AARP Exhibit 1.4 at page 4. The period Q1 2013 through Q1 2016 includes a range of average authorized ROE levels from a low of 9.4% in Q3 2015 to a high of 10.37% in Q1 2015. The 10.5% cost of equity included in the Settlement of Docket No. 120015-EI that was filed in Q3 2012 exceeded the monthly average ROE levels granted U.S. Investor Owned Electric Utilities in every month reported by EEI since Q1 2012. Notably, the 10.26% average awarded ROE in Q1 2016 in this report is characterized by EEI at page 1 under "HIGHLIGHTS" as "…boosted by a Virginia Electric & Power case that included ROE incentives" as more fully explained on page 5.

Q. What is your recommendation to the Commission regarding the ROE that should be awarded FPL in this Docket?

A. I recommend that FPL's authorized ROE be reduced from levels approved in the Company's last litigated rate case, based upon careful consideration of all of the cost of equity evidence offered by FPL and the other parties in this Docket, so as to reflect the general trend of declining costs in U.S. capital markets since 2009 in a manner consistent with the general lower recently authorized ROE levels found reasonable for U.S. Investor Owned utilities across the Country. I also recommend no performance bonus to increase the authorized ROE, as recommended by FPL witness Dewhurst, for the reasons explained in my testimony below.

V. EQUITY RATIO

Q. What was FPL's equity ratio that was used to establish revenue requirements approved in Docket No. 080677-EI?

A. Order No. PSC-10-0153-FOF-IE described the many controversial issues surrounding FPL's proposed equity ratio and ultimately accepted the Company's proposed equity ratio as a percentage of investor capital, stating:

> Based on the foregoing, we approve the capital structure shown on Schedule 2, attached to this order. This capital structure reflects an equity ratio as a percentage of investor capital of 59.1 percent for 2010. While this relative level of equity is near the top of the range of equity ratios of the IOUs owned by the companies in witness Avera's proxy group, it is still within the range of equity ratios of comparably rated IOUs. In addition, this equity ratio is consistent with the relative level of equity FPL has maintained, on an adjusted basis, over the past decade.[59]

[59] Order No. PSC-10-0153-FOF-IE; Docket No. 080677-EI, page 119.

Q. Is the Company seeking to again employ a very high common equity ratio for ratemaking purposes?

A. Yes. FPL continues to maintain a very equity "thick" capital structure on its books and has proposed an equity ratio of 59.6 percent be used to set rates in this Docket No. 160021-EI. Mr. Dewhurst refers to this ratio as "based on investor sources" and notes that the equity ratio is reduced to 44.13 percent "based on all sources" when combined with customer deposits, deferred taxes and investment credits, which are non-investor supplied sources of capital.[60] The testimony that follows will refer to the equity ratio solely in the context of "investor sources" of capital, which considers only capital provided by equity and debt investors.

Q. What is the impact upon utility rates of using the Company's proposed relatively equity "thick" capital structure for ratemaking purposes?

A. Equity capital imposes a significantly higher cost rate upon ratepayers than long-term debt or short-term debt. First, common equity capital requires a higher percentage annual return than long-term debt, causing a larger equity ratio to increase the overall weighted average cost of capital. Additionally, equity capital requires a factor-up for income taxes because, unlike debt financing where interest payments are income tax deductible by the utility, the collection of common equity return from ratepayers has no corresponding tax deduction and therefore produces

[60] Direct Testimony of Moray Dewhurst, page 23.

taxable income and income tax expense that amplifies the equity return cost by about 1.6 times the nominal cost.[61]

Q. Can you illustrate this point by comparing the Company's asserted pretax[62] overall cost of investor-supplied capital, including FPL's proposed 59.6 percent common equity ratio, to the pretax cost of cost of capital that would result if the equity ratio were held to an industry average 47 percent?

A. Yes. The table below converts the FPL-proposed investor-supplied capital structure and cost rates, from MFR Schedule D-1 to its pretax return requirement, by factoring up the equity elements of the return for federal and state income taxes.[63]

Investor-Supplied Cost of Capital - per FPL Schedule D-1 (test year):

		Amount	TY Ratio	Cost %	Pretax %	Weighted
Common Equity	$	14,683	59.6%	11.50%	18.40%	10.96%
Long-Term Debt		9,358	38.0%	4.62%	4.62%	1.75%
Short-Term Debt		613	2.5%	1.88%	1.88%	0.05%
Total Investor Supplied	$	24,654	100.0%			
Pretax Overall Cost of Investor-Supplied Capital per FPL						12.76%

The Company's equity thick capitalization dramatically inflates the revenues that ratepayers must provide, in order to pay income taxes and provide an 11.5 percent return on so much equity capital. Every dollar of rate base that is supported by investor-supplied capital would require 12.7 cents of pretax return revenues under

61 MFR Schedule A-1 applies a "Net Operating Income Multiplier" of 1.63024 at line 14 to recognize that additional Net Operating Income for common equity investors requires this factor up for income taxes. MFR Schedule C-44, in turn, depicts the development of this factor, revealing that it includes Federal income taxes at a 35% rate, State income tax at 5.5% and a small additional allowance for regulatory assessments and bad debts.

62 "Pretax" means inclusive of the income taxes that are assessed on the net income that is required to provide the authorized equity return.

63 For this illustration, bad debts and regulatory assessments are ignored and a simplified 1.6 factor is applied to the equity component of investor supplied capital. It also assumes that no changes to deferred income taxes, customer deposits or investment tax credits that are included in the ratemaking capital structure would be caused by adoption of an alternative equity ratio for ratemaking purposes.

the Company's cost of capital proposal. In contrast, by remixing the investor-supplied elements of the capital structure to limit the equity ratio to an industry average 47 percent, while leaving FPL's excessive 11.5% ROE recommendation unchanged, one can observe the dramatically lower pretax return percentage that ratepayers are required support with revenues if more typical industry average equity capitalization ratios were employed:

Investor-Supplied Cost of Capital - Equity Ratio at 47% (test year):

		Amount	**TY Ratio**	**Cost %**	**Pretax %**	**Weighted**
Common Equity	$	11,587	47.0%	11.50%	18.40%	8.65%
Long-Term Debt		12,454	50.5%	4.62%	4.62%	2.33%
Short-Term Debt		613	2.5%	1.88%	1.88%	0.05%
Total Investor Supplied	$	24,654	100.0%			
Pretax Overall Cost of Investor-Supplied Capital at 47% Equity						11.03%

The pretax cost of investor supplied capital declines dramatically with lower equity included in the ratemaking capital structure.

Q. Using this illustrative information, how much higher are the revenue requirements in the Company's 2017 test year at FPL's proposed equity ratio, compared to industry average equity ratios?

A. Yes. Using FPL's asserted 2017 test year revenue requirement as an example, if the ratemaking capital structure were limited to a more typical 47 percent weighting of common equity within the financial capital structure used to set rates, holding all else constant in the Company's filing, the resulting revenue requirement in the 2017 test year would decline by approximately $426 million.[64]

Q. Would significant revenue requirement reductions also occur in the Company's proposed 2018 Subsequent year and 2019 Limited Scope Adjustment for the Okeechobee project if the equity ratio were limited to industry average levels?

A. Yes. Large reductions in revenue requirement would occur in every test year, if FPL were constrained by the Commission to a more typical, industry average level of equity capitalization.

Q. Why should reasonably "balanced" ratios of equity and debt capital be employed by electric utilities and be used to determined electric utility revenue requirement?

A. If one considered only the static difference in equity versus debt costs of capital, extremely high debt ratios would be desirable so as to maximize the "leverage" of utility income streams for the benefit of the utility and its ratepayers. As noted above, long term debt capital is much less costly than common equity and the return charged to ratepayers for debt capital is not subject to income taxes, a cost that greatly amplifies the cost of added equity capital. On the other hand, adding higher proportions of debt to the capital structure increases financial risk to the utility, because interest and principal repayment on debt is a fixed obligation that must paid regardless of variations in income. Higher debt "leverage" increases earnings

[64] Rate base for 2017 on MFR Schedule A-1 of $32,536 million, less $7,882 million supported by non-investor supplied capital in MFR Schedule D-1 of ($7,368 Deferred Taxes + $106 ITC + $407 Deposits), yields investor supplied capital of $24,654 million. Reducing the pretax return requirement on this amount of investor-supplied capital from 12.76% to 11.03% (a change of 1.73%) would reduce the revenue requirement by approximately $426 million.

volatility because reported income is reduced by interest expense, in amounts that grow whenever more debt is included in the capitalization of any business. This is why electric utilities generally maintain a balanced capital structure employing equity ratios that generally fall between 45 and 50 percent of total investor-supplied capital.

Q. How does FPL's equity ratio compare to the average equity ratios of other electric utilities?

A. By any comparison, the Company's proposed ratemaking equity ratio is excessive. According to AUS Monthly Utility Reports June 2016 issue, the average common equity ratio for a sample of 17 large investor owned electric utilities was only 46.1 percent.[65] I have included a copy of this report as AARP Exhibit 1.5 to my testimony. Similarly, an industry survey published by the Edison Electric Institute, the EEI 2015 Financial Review of Electric Utilities indicates a composite common equity ratio for the "Regulated" category of the U.S Investor-Owned Electric Utility Industry at 45.7 percent at year-end 2014 and 44.9 percent at year-end 2015.[66] As a third source of industry data, I downloaded current balance sheet statistics from Y Charts for 26 of the largest investor-owned electric utilities in North America and the average equity ratio for this group is 46.9 percent. This information is summarized in AARP Exhibit 1.6. Even FPL's own rate of return witness, Mr. Hevert, relies upon a proxy group of electric utilities with an indicated mean "%

[65] See AARP Exhibit 1.5, June 2016 AUS Utility Report, page 6. NextEra Energy is included at a reported common equity ratio of only 40.9 percent that is presented to the investment community on a consolidated basis. However, for ratemaking purposes a much higher 59.6% equity ratio is used, which has the effect of increasing FPL's revenue requirement.

[66] Edison Electric Institute, 2015 Financial Review, page 14, available at: http://www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/finreview/Documents/FinancialReview_2015.pdf "Regulated" electric utilities are those with greater than 80% of total asset subject to regulation.

Common Equity" ratio of about 53 percent for this group, a level significantly below FPL's proposed 59.6 % equity ratio. Notably, Mr. Hevert's selected proxy group includes several outlier utilities with equity ratios above 70 percent and includes no electric utilities with an equity ratio below 45 percent. [67]

Q. How does the actual consolidated equity ratio of FPL's parent company, NextEra Energy, Inc. compare to the equity thick capital structure that NextEra maintains within its FPL subsidiary?

A. The capitalization used for NextEra's consolidated business employs much less equity, so as to take advantage of the cost savings of increased debt leverage for shareholders. NextEra Energy, Inc. maintains a consolidated equity ratio of only 42 percent,[68] as of March 31, 2016, that is more consistent with typical electric utility industry capitalization policies. However, for ratemaking purposes, FPL proposes that the financial benefits of higher debt maintained on a consolidated basis by NextEra Energy, Inc. be ignored when determining utility rates in Florida.

Q. Is NextEra, Inc., through ownership control of FPL and its other subsidiaries, able to control the attribution of its equity capital among its various business units without impacting its overall, consolidated capital structure?

A. Yes. NextEra Energy, Inc., as controlling parent of FPL, has both the ability and a strong financial incentive to maximize the amount of equity capital that is directed into FPL's regulated utility balance sheet, because any additional FPL equity that is accepted by the Commission translates directly into higher revenue requirements. NextEra

[67] See FPL Exhibit RBH-10, page 1.
[68] NextEra, Inc. Condensed Consolidated Balance Sheets supporting SEC 8K reporting available at: http://www.investor.nexteraenergy.com/phoenix.zhtml?c=88486&p=EarningsRelease includes total equity of $23.6 billion, LT debt of $27.8 billion and commercial paper, notes payable and current maturities of LT debt of $1.6, $0.9 and $2.1 billion, respectively.

Energy Inc., as FPL's parent company, decides the timing and amounts of debt financing within each subsidiary, controls the infusion of equity capital into subsidiary units and directs the upstream dividend policies adopted by each subsidiary. The parent company's discretion around these decisions allows the consolidated business to adopt policies that maximize the common equity ratio within FPL that will be tolerated by the Commission because doing so maximizes utility revenue requirements and earnings.

Q. Has FPL presented any evidence to show that its equity "thick" capitalization policy for is cost effective for ratepayers?

A. No. FPL's proposed extremely high equity ratios should minimize financial risk and result in far below average required returns on equity capital. However, FPL has inexplicably proposed an ROE far above levels recently granted to other public utilities in spite of its equity thick capitalization. Thus, there is no offsetting ROE benefit to FPL ratepayers attributed to the very costly equity thick capitalization that is proposed. I have seen no evidence from FPL quantifying how its equity ratio exceeding 59 percent applied to a proposed ROE of 11.5 percent, which both representing levels significantly higher than industry norms, can be considered cost effective from the perspective of ratepayers. Even when consideration is given to any incremental benefits from higher credit ratings or lower costs upon newly issued debt, the much higher nominal costs of equity capital and related income taxes that are imposed upon ratepayers argue for use of a normalized equity ratio for ratemaking purposes.

Q. Do you recommend that the Commission employ either an industry average equity ratio not exceeding 47 percent or the much lower consolidated equity ratio of NextEra, Inc. in determining revenue requirements, in place of the equity "thick" capitalization that is recorded on FPL books?

A. Yes. Absent compelling evidence that FPL ratepayers are better off with the additional equity capital that NextEra maintains within the regulated utility, I recommend that the common equity ratio allowed by the Commission not exceed the high end of the range of published industry averages of 47 percent level in the previously mentioned AUS Report, and levels reported by EEI for 2015 and Y Charts in 2016.

VI. EFFICIENCY INCENTIVES / ROE BONUS

Q. FPL witness Mr. Dewhurst argues that the Commission should grant the Company "an ROE performance adder of 50 basis points" when setting rates.[69] Do you agree that this is appropriate as a matter of regulatory policy to "reflect what FPL has already accomplished" and to promote further efforts to improve the customer value proposition" as suggested by Mr. Dewhurst?

A. No. It is the responsibility of utility management to constantly strive for the provision of safe and reliable service at the lowest practical cost and there is no need to burden ratepayers with higher rates in the form of an ROE bonus for such efforts. FPL and NextEra shareholders have been richly rewarded in every year of the past decade with consistently strong earnings under the existing regulatory framework in Florida, without adding another layer of prospective rewards for investors.[70] Additionally, I understand that FPL has included in its revenue requirement significant costs for incentive compensation that is expected to be awarded to utility employees and management,

[69] Direct Testimony of Moray Dewhurst, pages 5, 8, 17 and 27-32.

[70] FPL's response to AARP Interrogatory No. 10 indicates FPL's actual return on average common equity from 2006 through 2015 stayed within a narrow range of 10.14% (in 2009) and 12.01% (in 2006) in spite of the major recession years experienced after 2007.

based upon their anticipated ongoing efforts to improve service quality and efficiency,[71] so any further bonus payments to shareholders for the same performance would be redundant.

Q. Mr. Dewhurst admits that "all utilities with an obligation to serve will naturally strive to deliver good value" but that his experience, "…suggests that there can be substantial degrees of difference in how intensively different companies pursue opportunities to improve" and because of this he claims, "…[a] performance adder would provide positive, economic encouragement to induce a higher degree of innovation and a higher degree of 'stretch' in pursuit of superior outcomes, encouraging utilities to develop initiatives and programs that have the potential to generate savings and improve productivity."[72] Do you agree with these theories?

A. No. An ROE bonus reward is a blunt instrument that would be very costly to ratepayers. Mr. Dewhurst and FPL have not shown the proposed bonus to be cost-effective in relation to any specifically extraordinary risks taken or achievements accomplished by the utility. Adding 50 basis points to the ROE would charge ratepayers an extra $119 million annually, based upon the Company's proposed rate base and equity ratio in the 2017 test year.[73] Mr. Dewhurst and Mr. Reed have not quantified specific and unique benefits that FPL will achieve incrementally in <u>each future year</u> to justify these extra annual charges to customers. In fact, as noted in my prior testimony, the Company's rate case forecasts do not include any assumed incremental productivity measures that

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[71] See FPL responses to Staff Interrogatories 16-21.
[72] Direct Testimony of Moray Dewhurst, pages 29-30.
[73] The overall ROR at an 11% ROE in 2017 on MFR Schedule D-1 would decline to 6.38%, which would flow through Schedule A-1 and reduce the required net operating income by $73.4 million, then be multiplied by the conversion factor of 1.6x.

would reduce future charges to customers as an offset to the return bonus then being collected.

Q. Does the fact that FPL is proposing large base rate increases in its filing in this Docket undermine the claims of Mr. Dewhurst that the Company's cost controls are better than an average utility?

A. Yes. Mr. Dewhurst and other FPL witnesses repeatedly reference the Company's success in controlling the growth in non-fuel O&M expenses.[74] However, non-fuel O&M expenses are only one element of the Company's revenue requirement and do not tell the complete story regarding cost controls. The primary driver of FPL-proposed rate increases is the large amounts of capital spending that are planned and forecasted and this is where cost control could be most important to the Company and its ratepayers. The fact that large base rate increases are believed to be required by FPL in each of the next three years is an admission that the Company has limited control over its total cost of service, including capital expenditures and the depreciation of capital assets.

Q. Mr. Dewhurst and other FPL witnesses refer to the Company's electric rates in comparison to other electric utilities in Florida and elsewhere.[75] Is much of this comparison influenced by FPL's heavy reliance upon natural gas fuel and the favorable trends in market prices for that fuel source?

A. Yes. As indicated in my prior testimony, FPL management cannot realistically claim credit for the large historical declines in natural gas market prices. Additionally, the Company's fuel adjustment procedures will ensure that electric rates will trend upward in the future if natural gas generation fuel market prices rebound.

[74] See Direct Testimony of Moray Dewhurst at page 28 and of John Reed at pages 24-25.

[75] Direct Testimony of Moray Dewhurst, page 11, Direct Testimony of Tiffany Cohen, pages 6-7, Direct Testimony of Eric Silagy, pages 4-5.

Q. Should FPL be rewarded prospectively for claimed management performance achievements historically?

A. No. Any prospective awards should be tied to future performance. It is important to note that FPL shareholders will be rewarded prospectively with higher earnings in each instance where future cost reductions are achieved by management, because of regulatory lag and the use of forecasted test year in Florida. Unfortunately, this same reward system also provides a strong incentive for overstatement of rate case test year forecasts, making it difficult to distinguish how much of any improved earnings caused by favorable expense and investment variances relative to forecast levels are the result of management performance or overly pessimistic forecasts.

Q. Mr. Dewhurst states that the factors the Commission should consider in evaluating ROE performance bonuses for electric utilities include, "…cost or affordability, reliability of service, and customer service quality" as well as "FPL's comparative emissions rates, particularly of CO2, the principal long-term driver of climate change." Has FPL proposed any specific metrics or committed to any incremental future improvement targets for any of these proposed "factors" as a condition for the recommended ROE adder?

A. No. If Mr. Dewhurst or FPL are proposing an incentive regulation framework that is more than a reward for claimed past performance, the Company would need to commit to specific measurable <u>future</u> goals and then set the value of any rewards from ratepayers in a manner that is carefully calibrated so that the size of each reward was proportionate to the value of the improvement actually achieved. Presumably, such a system would also require that FPL bake into its rate case forecasts the anticipated performance levels for cost reductions, to ensure that ratepayers actually receive the benefits for which rewards are paid.

Q. Is there a less complicated and more precise way for targeted incentives to be directed to utility employees and management personnel who are directly able to effect beneficial service quality and cost efficiency changes through their day to day actions?

A. Yes. The incentive compensation plans that most utilities have installed are designed to reward employees for performance, in a cost-effective manner that tailors the size of any rewards to achieved results as part of an overall package of compensation. FPL employs such incentive compensation arrangements. According to the Company's SEC filings, the FPL incentive compensation goals adopted for 2015 included metrics for controlling O&M costs, capital expenditures, fossil generation availability, nuclear unit performance, service reliability, employee safety, environmental compliance, customer satisfaction and performance against FERC/NERC reliability standards.[76]

Q. Has Mr. Dewhurst or FPL proposed that ROE penalties be assessed when utilities perform poorly?

A. No.[77] Presumably, utility ratepayers should always pay more for good service through a bonus ROE adder, but not receive any relief from higher rates when performance is

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[76] See NextEra Energy, Inc. SEC Schedule 14A Proxy Statement filed with the SEC on 4/21/2016 to announce NextEra's Annual Meeting of shareholders, page 68. AARP Interrogatory Nos. 39 and 40 asked for more details regarding FPL incentive compensation costs, but the Company declined to answer any of these questions, by improperly interpreting AARP's questions as limited to incentive compensation for the Named Executive Officers discussed in the SEC filing.

[77] Mr. Dewhurst discounts penalty provisions at page 31 of his testimony, stating, "While penalties for deliberately or negligently poor performance may be appropriate in some circumstances, in the vast majority of cases regulated utilities are seeking to provide good value to customers. The practical issue is how to encourage new and different approaches in order to advance the "state of the art" in providing service to customers."

unremarkable. This is a clearly unbalanced view of how regulation should work, that should be rejected by the Commission.

VII. RESIDENTIAL CUSTOMER CHARGES

Q. WHAT CHANGES TO RESIDENTIAL CUSTOMER CHARGES ARE PROPOSED BY FPL IN THIS DOCKET?

A. According to FPL witness Ms. Cohen, "FPL also proposes a $2.00 increase to the RS-1 Customer Charge to recover a portion of fixed distribution costs currently being recovered through the variable energy charge." She explains this proposal by stating that, "…over 80 percent of FPL's costs recovered through base rates are fixed costs, while only 26 percent of these fixed costs are recovered through a fixed charge. In order to more closely align recovery of fixed costs with fixed charges, FPL is proposing this modest customer charge increase."[78]

Q. Is it necessary or reasonable to recover more of a utility's "fixed costs" to serve residential customers through a "fixed charge" as suggested by Ms. Cohen?

A. No. There are important public policy reasons why electric utilities typically do not have very high fixed residential monthly customer charges, even though the majority of the utility's costs other than fuel and purchased energy are relatively fixed and do not vary with kWh consumption levels. Low residential customer charges are desirable as a matter of public policy because they:

[78] Direct Testimony of Tiffany Cohen, page 18. Exhibit TCC-6 at page 3 states that the proposed RS-1 customer charge of $10.00 would be further increased to $10.30 in 2019 "…to account for the LSA increase percentage" arising from Okeechobee piecemeal rate increases being proposed by the Company at that time.

1. Increase the degree of control residential customers have over their monthly energy bills, by reducing the fixed charge at zero or minimal energy usage.
2. Improve affordability for low income customers that also have low monthly energy usage levels.
3. Encourage energy conservation habits with larger per-kWh savings rewards.
4. Improve the payback on energy efficiency investments with larger bill savings for each kWh of ongoing reduced energy consumption.

It is not practical or desirable to maintain fully cost-based residential customer charge rates because of these important public policy considerations.

Q. Has the Company provided any cost justification for an increase in its residential customer charge in this Docket?

A. No. The Company's cost of service evidence actually supports no increase in this rate element. FPL's existing customer charge of $7.87 per month[79] more than covers the monthly fixed "customer" costs that are incurred by FPL to provide meters, meter reading, service lines, billing, collection and other costs to connect and serve each residential customer, while providing a small contribution to remaining fixed costs.[80] The other demand-related fixed costs allocable to the residential class for the production, transmission and network distribution facilities that are needed to serve residential customers cannot be recovered through a "demand" rate because such a rate element does not exist in the residential rate structure. Therefore, these costs are properly

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[79] MFR No. E-14, Attachment 1 of 6, page 11 shows the RS-1 Customer Charge increasing from $7.87 to $10.00 per month.

[80] See, for example, MFR No. E-6a, Attachment 2, page 8, line 2, where "Customer" unit costs for the RS(T)-1 class equal $6.603212 using the 12cp 25 methodology proposed by FPL.

recovered through the per-kWh residential energy rate, to the extent not recovered through the monthly customer charge rate element.

Additionally, for the reasons stated in my testimony, it is obvious the FPL's overall asserted rate increase amounts over the next three years have been overstated. If the Commission concludes that the Company's revenue requirement is much smaller than indicated by FPL's filed MFR schedules, there is even less reason to increase monthly residential customer charges.

Q. Does this conclude your testimony at this time?

A. Yes.

Michael L. Brosch
Utilitech, Inc. – President
Bachelor of Business Administration (Accounting)
University of Missouri-Kansas City (1978)
Certified Public Accountant Examination (1979)

GENERAL

Mr. Brosch serves as the director of regulatory projects for the firm and is responsible for the planning, supervision and conduct of firm engagements. His academic background is in business administration and accounting and he holds CPA certificates in Kansas and Missouri. Expertise is concentrated within regulatory policy, financial and accounting areas with an emphasis in revenue requirements, business reorganization, cost allocations, rate design and alternative regulation.

EXPERIENCE

Mr. Brosch has supervised and conducted the preparation of rate case exhibits and testimony in support of revenue requirements and regulatory policy issues involving more than 100 electric, gas, telephone, water, and sewer proceeding across the United States. Responsible for virtually all facets of revenue requirement determination, cost of service allocations and tariff implementation in addition to involvement in numerous utility merger, alternative regulation and other special project investigations.

Industry restructuring analysis for gas utility rate unbundling, electric deregulation, competitive bidding and strategic planning, with testimony on regulatory processes, asset identification and classification, revenue requirement and unbundled rate designs and class cost of service studies.

Analyzed and presented testimony regarding income tax related issues within ratemaking proceedings involving interpretation of relevant IRS code provisions and regulatory restrictions.

Has substantial experience in the application of lead-lag study concepts and methodologies in determination of working capital investment to be included in rate base.

Conducted alternative regulation analyses for clients in Arizona, California, Hawaii, Illinois, Texas and Oklahoma, focused upon challenges introduced by cost-based regulation, incentive effects available through alternative regulation and balancing of risks, opportunities and benefits among stakeholders. Analyses included targeted rate adjustment clauses, regulatory deferral accounting mechanisms, revenue/price cap arrangements and formula rate adjustment programs, including advisory work in the design of such plans as well as analyses and administration of alternative regulation plans after implementation.

Mr. Brosch managed the detailed regulatory review of utility mergers and acquisitions, diversification studies and holding company formation issues in energy and telecommunications transactions in multiple states. Sponsored testimony regarding merger synergies, merger accounting and tax implications, regulatory planning and price path strategies. Traditional horizontal utility mergers as well as leveraged buyouts of utility properties by private equity investors have been addressed in several states.

Analyzed and developed alternative regulation plans for electric and gas utilities in multiple states. Participated in the development, implementation and administration of decoupling and formula rate adjustment mechanisms. Advised and assisted in legislative advocacy regarding electric and gas infrastructure rate adjustment mechanisms.

WORK HISTORY

1985 - Present **President** - Utilitech, Inc.
Regulatory project management and advisory/consulting services on behalf of industry and governmental agencies.

1983 - 1985: **Project manager** - Lubow McKay Stevens and Lewis.
Responsible for supervision and conduct of utility regulatory projects on behalf of industry and regulatory agency clients.

1982 - 1983: **Regulatory consultant** - Troupe Kehoe Whiteaker and Kent.
Responsible for management of rate case activities involving analysis of utility operations and results, preparation of expert testimony and exhibits, and issue development including research and legal briefs. Also involved in numerous special projects including financial analysis and utility systems planning. Taught firm's professional education course on "utility income taxation - ratemaking and accounting considerations" in 1982.

1978 - 1982: **Senior Regulatory Accountant** - Missouri Public Service Commission.
Supervised and conducted rate case investigations of utilities subject to PSC jurisdiction in response to applications for tariff changes. Responsibilities included development of staff policy on ratemaking issues, planning and evaluating work of outside consultants, and the production of comprehensive testimony and exhibits in support of rate case positions taken.

OTHER QUALIFICATIONS

Bachelor of Business Administration - Accounting, 1978
University of Missouri - Kansas City

Member American Institute of Certified Public Accountants
Missouri Society of Certified Public Accountants
Kansas Society of Certified Public Accountants

Attended Iowa State Regulatory Conference 1981, 1985
Regulated Industries Symposium 1979, 1980
Michigan State Regulatory Conference 1981
United States Telephone Association Round Table 1984
NARUC/NASUCA Annual Meeting 1988, Speaker
NARUC/NASUCA Annual Meeting 2000, Speaker
NASUCA Regional Consumer Protection Meeting 2007, Speaker

Instructor INFOCAST Ratemaking Courses
Arizona Staff Training
Hawaii Staff Training

Utility Company	State	Tribunal	Case Number	Client	Year	Issues Addressed
Green Hills Telephone Company	Missouri	PSC	TR-78-282	Staff	1978	Rate Base, Operating Income
Kansas City Power and Light Co.	Missouri	PSC	ER-78-252	Staff	1978	Rate Base, Operating Income
Missouri Public Service Company	Missouri	PSC	ER-79-59	Staff	1979	Rate Base, Operating Income
Nodaway Valley Telephone Company	Missouri	PSC	16,567	Staff	1979	Rate Base, Operating Income
Gas Service Company	Missouri	PSC	GR-79-114	Staff	1979	Rate Base, Operating Income
United Telephone Company	Missouri	PSC	TO-79-227	Staff	1979	Rate Base, Operating Income
Southwestern Bell Telephone Co.	Missouri	PSC	TR-79-213	Staff	1979	Rate Base, Operating Income
Missouri Public Service Company	Missouri	PSC	ER-80-118 GR-80-117	Staff	1980	Rate Base, Operating Income
Southwestern Bell Telephone Co.	Missouri	PSC	TR-80-256	Staff	1980	Affiliate Transactions
United Telephone Company	Missouri	PSC	TR-80-235	Staff	1980	Affiliate Transactions, Cost Allocations
Kansas City Power and Light Co.	Missouri	PSC	ER-81-42	Staff	1981	Rate Base, Operating Income
Southwestern Bell Telephone	Missouri	PSC	TR-81-208	Staff	1981	Rate Base, Operating Income, Affiliated Interest
Northern Indiana Public Service	Indiana	PSC	36689	Consumers Counsel	1982	Rate Base, Operating Income
Northern Indiana Public Service	Indiana	URC	37023	Consumers Counsel	1983	Rate Base, Operating Income, Cost Allocations
Mountain Bell Telephone	Arizona	ACC	9981-E1051-81-406	Staff	1982	Affiliated Interest
Sun City Water	Arizona	ACC	U-1656-81-332	Staff	1982	Rate Base, Operating Income
Sun City Sewer	Arizona	ACC	U-1656-81-331	Staff	1982	Rate Base, Operating Income
El Paso Water	Kansas	City Counsel	Unknown	Company	1982	Rate Base, Operating Income, Rate of Return
Ohio Power Company	Ohio	PUCO	83-98-EL-AIR	Consumer Counsel	1983	Operating Income, Rate Design, Cost Allocations
Dayton Power & Light Company	Ohio	PUCO	83-777-GA-AIR	Consumer Counsel	1983	Rate Base
Walnut Hill Telephone	Arkansas	PSC	83-010-U	Company	1983	Operating Income, Rate Base
Cleveland Electric Illum.	Ohio	PUCO	84-188-EL-AIR	Consumer Counsel	1984	Rate Base, Operating Income, Cost Allocations
Cincinnati Gas & Electric	Ohio	PUCO	84-13-EL-EFC	Consumer Counsel	1984	Fuel Clause
Cincinnati Gas & Electric	Ohio	PUCO	84-13-EL-EFC (Subfile A)	Consumer Counsel	1984	Fuel Clause
General Telephone - Ohio	Ohio	PUCO	84-1026-TP-AIR	Consumer Counsel	1984	Rate Base
Cincinnati Bell Telephone	Ohio	PUCO	84-1272-TP-AIR	Consumer Counsel	1985	Rate Base
Ohio Bell Telephone	Ohio	PUCO	84-1535-TP-AIR	Consumer Counsel	1985	Rate Base

Utility Company	State	Tribunal	Case Number	Client	Year	Issues Addressed
United Telephone - Missouri	Missouri	PSC	TR-85-179	Staff	1985	Rate Base, Operating Income
Wisconsin Gas	Wisconsin	PSC	05-UI-18	Staff	1985	Diversification-Restructuring
United Telephone - Indiana	Indiana	URC	37927	Consumer Counsel	1986	Rate Base, Affiliated Interest
Indianapolis Power & Light	Indiana	URC	37837	Consumer Counsel	1986	Rate Base
Northern Indiana Public Service	Indiana	URC	37972	Consumer Counsel	1986	Plant Cancellation Costs
Northern Indiana Public Service	Indiana	URC	38045	Consumer Counsel	1986	Rate Base, Operating Income, Cost Allocations, Capital Costs
Arizona Public Service	Arizona	ACC	U-1435-85-367	Staff	1987	Rate Base, Operating Income, Cost Allocations
Kansas City, KS Board of Public Utilities	Kansas	BPU	87-1	Municipal Utility	1987	Operating Income, Capital Costs
Detroit Edison	Michigan	PSC	U-8683	Industrial Customers	1987	Income Taxes
Consumers Power	Michigan	PSC	U-8681	Industrial Customers	1987	Income Taxes
Consumers Power	Michigan	PSC	U-8680	Industrial Customers	1987	Income Taxes
Northern Indiana Public Service	Indiana	URC	38365	Consumer Counsel	1987	Rate Design
Indiana Gas	Indiana	URC	38080	Consumer Counsel	1987	Rate Base
Northern Indiana Public Service	Indiana	URC	38380	Consumers Counsel	1988	Rate Base, Operating Income, Rate Design, Capital Costs
Terre Haute Gas	Indiana	URC	38515	Consumers Counsel	1988	Rate Base, Operating Income, Capital Costs
United Telephone -Kansas	Kansas	KCC	162,044-U	Consumers Counsel	1989	Rate Base, Capital Costs, Affiliated Interest
US West Communications	Arizona	ACC	E-1051-88-146	Staff	1989	Rate Base, Operating Income, Affiliate Interest
All Kansas Electrics	Kansas	KCC	140,718-U	Consumers Counsel	1989	Generic Fuel Adjustment Hearing
Southwest Gas	Arizona	ACC	E-1551-89-102 E-1551-89-103	Staff	1989	Rate Base, Operating Income, Affiliated Interest
American Telephone and Telegraph	Kansas	KCC	167,493-U	Consumers Counsel	1990	Price/Flexible Regulation, Competition, Revenue Requirements
Indiana Michigan Power	Indiana	URC	38728	Consumer Counsel	1989	Rate Base, Operating Income, Rate Design
People Gas, Light and Coke Company	Illinois	ICC	90-0007	Public Counsel	1990	Rate Base, Operating Income
United Telephone Company	Florida	PSC	891239-TL	Public Counsel	1990	Affiliated Interest
Southwestern Bell Telephone Company	Oklahoma	OCC	PUD-000662	Attorney General	1990	Rate Base, Operating Income (Testimony not admitted)
Arizona Public Service Company	Arizona	ACC	U-1345-90-007	Staff	1991	Rate Base, Operating Income

Utility Company	State	Tribunal	Case Number	Client	Year	Issues Addressed
Indiana Bell Telephone Company	Indiana	URC	39017	Consumer Counsel	1991	Test Year, Discovery, Schedule
Southwestern Bell Telephone Company	Oklahoma	OCC	39321	Attorney General	1991	Remand Issues
UtiliCorp United/ Centel	Kansas	KCC	175,476-U	Consumer Counsel	1991	Merger/Acquisition
Southwestern Bell Telephone Company	Oklahoma	OCC	PUD-000662	Attorney General	1991	Rate Base, Operating Income
United Telephone - Florida	Florida	PSC	910980-TL	Public Counsel	1992	Affiliated Interest
Hawaii Electric Light Company	Hawaii	PUC	6999	Consumer Advocate	1992	Rate Base, Operating Income, Budgets/Forecasts
Maui Electric Company	Hawaii	PUC	7000	Consumer Advocate	1992	Rate Base, Operating Income, Budgets/Forecasts
Southern Bell Telephone Company	Florida	PSC	920260-TL	Public Counsel	1992	Affiliated Interest
US West Communications	Washington	WUTC	U-89-3245-P	Attorney General	1992	Alternative Regulation
UtiliCorp United/ MPS	Missouri	PSC	ER-93-37	Staff	1993	Affiliated Interest
Oklahoma Natural Gas Company	Oklahoma	OCC	PUD-1151, 1144, 1190	Attorney General	1993	Rate Base, Operating Income, Take or Pay, Rate Design
Public Service Company of Oklahoma	Oklahoma	OCC	PUD-1342	Staff	1993	Rate Base, Operating Income, Affiliated Interest
Illinois Bell Telephone	Illinois	ICC	92-0448 92-0239	Citizens Board	1993	Rate Base, Operating Income, Alt. Regulation, Forecasts, Affiliated Interest
Hawaii Electric Company	Hawaii	PUC	7700	Consumer Advocate	1993	Rate Base, Operating Income
US West Communications	Arizona	ACC	E-1051-93-183	Staff	1994	Rate Base, Operating Income
PSI Energy, Inc.	Indiana	URC	39584	Consumer Counselor	1994	Rate Base, Operating Income, Alt. Regulation, Forecasts, Affiliated Interest
Arkla, a Division of NORAM Energy	Oklahoma	OCC	PUD-940000354	Attorney General	1994	Cost Allocations, Rate Design
PSI Energy, Inc.	Indiana	URC	39584-S2	Consumer Counselor	1994	Merger Costs and Cost Savings, Non-Traditional Ratemaking
Transok, Inc.	Oklahoma	OCC	PUD-1342	Staff	1994	Rate Base, Operating Income, Affiliated Interest, Allocations
Oklahoma Natural Gas Company	Oklahoma	OCC	PUD-940000477	Attorney General	1995	Rate Base, Operating Income, Cost of Service, Rate Design
US West Communications	Washington	WUTC	UT-950200	Attorney General/ TRACER	1995	Operating Income, Affiliate Interest, Service Quality
PSI Energy, Inc.	Indiana	URC	40003	Consumer Counselor	1995	Rate Base, Operating Income

Utility Company	State	Tribunal	Case Number	Client	Year	Issues Addressed
Oklahoma Natural Gas Company	Oklahoma	OCC	PUD-880000598	Attorney General	1995	Stand-by Tariff
GTE Hawaiian Telephone Co., Inc.	Hawaii	PUC	PUC 94-0298	Consumer Advocate	1996	Rate Base, Operating Income, Affiliate Interest, Cost Allocations
Mid-American Energy Company	Iowa	ICC	APP-96-1	Consumer Advocate	1996	Non-Traditional Ratemaking
Oklahoma Gas and Electric Company	Oklahoma	OCC	PUD-960000116	Attorney General	1996	Rate Base, Operating Income, Rate Design, Non-Traditional Ratemaking
Southwest Gas Corporation	Arizona	ACC	U-1551-96-596	Staff	1997	Operating Income, Affiliated Interest, Gas Supply
Utilicorp United - Missouri Public Service Division	Missouri	PSC	EO-97-144	Staff	1997	Operating Income
US West Communications	Utah	PSC	97-049-08	Consumer Advocate	1997	Rate Base, Operating Income, Affiliate Interest, Cost Allocations
US West Communications	Washington	WUTC	UT-970766	Attorney General	1997	Rate Base, Operating Income
Missouri Gas Energy	Missouri	PSC	GR 98-140	Public Counsel	1998	Affiliated Interest
ONEOK	Oklahoma	OCC	PUD980000177	Attorney General	1998	Gas Restructuring, rate Design, Unbundling
Nevada Power/Sierra Pacific Power Merger	Nevada	PSC	98-7023	Consumer Advocate	1998	Merger Savings, Rate Plan and Accounting
PacifiCorp / Utah Power	Utah	PSC	97-035-1	Consumer Advocate	1998	Affiliated Interest
MidAmerican Energy / CalEnergy Merger	Iowa	PUB	SPU-98-8	Consumer Advocate	1998	Merger Savings, Rate Plan and Accounting
American Electric Power / Central and South West Merger	Oklahoma	OCC	980000444	Attorney General	1998	Merger Savings, Rate Plan and Accounting
ONEOK Gas Transportation	Oklahoma	OCC	970000088	Attorney General	1998	Cost of Service, Rate Design, Special Contract
U S West Communications	Washington	WUTC	UT-98048	Attorney General	1999	Directory Imputation and Business Valuation
U S West / Qwest Merger	Iowa	PUB	SPU 99-27	Consumer Advocate	1999	Merger Impacts, Service Quality and Accounting
U S West / Qwest Merger	Washington	WUTC	UT-991358	Attorney General	2000	Merger Impacts, Service Quality and Accounting
U S West / Qwest Merger	Utah	PSC	99-049-41	Consumer Advocate	2000	Merger Impacts, Service Quality and Accounting
PacifiCorp / Utah Power	Utah	PSC	99-035-10	Consumer Advocate	2000	Affiliated Interest
Oklahoma Natural Gas, ONEOK Gas Transportation	Oklahoma	OCC	980000683, 980000570, 990000166	Attorney General	2000	Operating Income, Rate Base, Cost of Service, Rate Design, Special Contract
U S West Communications	New Mexico	PRC	3008	Staff	2000	Operating Income, Directory Imputation
U S West Communications	Arizona	ACC	T-0105B-99-0105	Staff	2000	Operating Income, Rate Base, Directory Imputation
Northern Indiana Public Service Company	Indiana	IURC	41746	Consumer Counsel	2001	Operating Income, Rate Base, Affiliate Transactions

Utility Company	State	Tribunal	Case Number	Client	Year	Issues Addressed
Nevada Power Company	Nevada	PUCN	01-10001	Attorney General-BCP	2001	Operating Income, Rate Base, Merger Costs, Affiliates
Sierra Pacific Power Company	Nevada	PUCN	01-11030	Attorney General-BCP	2002	Operating Income, Rate Base, Merger Costs, Affiliates
The Gas Company, Division of Citizens Communications	Hawaii	PUC	00-0309	Consumer Advocate	2001	Operating Income, Rate Base, Cost of Service, Rate Design
SBC Pacific Bell	California	PUC	I.01-09-002 R.01-09-001	Office of Ratepayer Advocate	2002	Depreciation, Income Taxes and Affiliates
Midwest Energy, Inc.	Kansas	KCC	02-MDWG-922-RTS	Agriculture Customers	2002	Rate Design, Cost of Capital
Qwest Communications – Dex Sale	Utah	PSC	02-049-76	Consumer Advocate	2003	Directory Publishing
Qwest Communications – Dex Sale	Washington	WUTC	UT-021120	Attorney General	2003	Directory Publishing
Qwest Communications – Dex Sale	Arizona	ACC	T-0105B-02-0666	Staff	2003	Directory Publishing
PSI Energy, Inc.	Indiana	IURC	42359	Consumer Counsel	2003	Operating Income, Rate Trackers, Cost of Service, Rate Design
Qwest Communications – Price Cap Review	Arizona	ACC	T-0105B-03-0454	Staff	2004	Operating Income, Rate Base, Fair Value, Alternative Regulation
Verizon Northwest Corp	Washington	WUTC	UT-040788	Public Counsel	2004	Directory Publishing, Rate Base, Operating Income
Citizens Gas & Coke Utility	Indiana	IURC	42767	Consumer Counsel	2005	Operating Income, Debt Service, Working Capital, Affiliate Transactions, Alternative Regulation
Hawaiian Electric Company	Hawaii	HPUC	04-0113	Consumer Advocate	2005	Operating Income, Rate Base, Cost of Service, Rate Design
Sprint/Nextel Corporation	Washington	WUTC	UT-051291	Public Counsel	2006	Directory Publishing, Corporate Reorganization
Puget Sound Energy, Inc.	Washington	WUTC	UE-060266 and UG-060267	Public Counsel	2006	Alternative Regulation
Hawaiian Electric Company	Hawaii	HPUC	05-0146	Consumer Advocate	2006	Community Benefits / Rate Discounts
Cascade Natural Gas Company	Washington	WUTC	UG-060259	Public Counsel	2006	Alternative Regulation
Arizona Public Service Company	Arizona	ACC	E-01345A-05-0816	Staff	2006	Cost of Service Allocations
Hawaiian Electric Company	Hawaii	HPUC	05-0146	Consumer Advocate	2006	Capital Improvements and Discounted Rates
Hawaii Electric Light Company	Hawaii	HPUC	05-0315	Consumer Advocate	2006	Operating Income, Rate Base, Cost of Service, Rate Design

Utility Company	State	Tribunal	Case Number	Client	Year	Issues Addressed
Union Electric Company d/b/a AmerenUE	Missouri	PSC	2007-0002	Attorney General	2007	Operating Income, Rate Base, Fuel Adjustment Clause
Hawaiian Electric Company	Hawaii	PUC	2006-0386	Consumer Advocate	2007	Operating Income, Cost of Service, Rate Design
Maui Electric Company	Hawaii	PUC	2006-0387	Consumer Advocate	2007	Operating Income, Cost of Service, Rate Design
The Peoples Gas Light & Coke Company / North Shore Gas Company	Illinois	ICC	07-0241 07-0242	Attorney General	2007	Rate Adjustment Clauses
Commonwealth Edison	Illinois	ICC	07-0566	Attorney General, City	2008	Ratemaking Policy, Rate Trackers
Illinois Power Company, Illinois Public Service Co., Central Illinois Public Service Co.	Illinois	ICC	07-0585 cons.	Attorney General/CUB	2008	Rate Adjustment Clauses
Southwestern Public Service Company	Texas	PUCT	35763	Municipalities	2008	Operating Income, Rate Base, Affiliate Transactions
The Gas Company	Hawaii	PUC	2008-0081	Consumer Advocate	2009	Operating Income, Rate Base, Affiliate Transactions, Cost of Service, Rate Design
Hawaiian Electric Company	Hawaii	PUC	2008-0083	Consumer Advocate	2009	Operating Income, Rate Base, Affiliate Transactions, Cost of Service, Rate Design
Commonwealth Edison Company	Illinois	ICC	09-0263	Attorney General	2009	Rate Adjustment Clauses
Avista Corporation Washingon WUTC	Washington	WUTC	UG-060518	Attorney General	2009	Rate Adjustment Clauses
Kauai Island Utility Cooperative	Hawaii	PUC	2009-0050	Consumer Advocate	2009	Operating Income, Cooperative Ratemaking Policies, Cost of Service
Maui Electric Company	Hawaii	PUC	2009-0163	Consumer Advocate	2010	Operating Income, Rate Base, Cost of Service, Rate Design
Hawaii Electric Light Company	Hawaii	PUC	2009-0164	Consumer Advocate	2010	Operating Income, Rate Base, Cost of Service, Rate Design
Commonwealth Edison Company	Illinois	ICC	10-0467	AG / CUB	2010	Operating Income, Rate Base
Commonwealth Edison Company	Illinois	ICC	10-0527	Attorney General	2010	Alternative Regulation
Atmos Pipeline - Texas	Texas	RCT	GUD 10000	ATM Cities	2010	Operating Income, Rate Base, Cost of Service, Rate Adjustment Clause
Ameren Missouri	Missouri	PSC	2011-0028	Industrial Customers	2011	Operating Income, Rate Base

Utility Company	State	Tribunal	Case Number	Client	Year	Issues Addressed
Hawaiian Electric Company	Hawaii	PUC	2010-0080	Consumer Advocate	2011	Operating Income, Rate Base, Affiliate Transactions, Cost of Service, Rate Design
Utilities, Inc.	Illinois	ICC	11-0561..0566	Attorney General	2011	Operating Income, Rate Base, Rate Design
Commonwealth Edison Company	Illinois	ICC	11-0721	AG / CUB	2011	Alternative Regulation
Utilities, Inc.	Illinois	ICC	11-0059 RH	AG	2012	Rate Design
Maui Electric, Ltd.	Hawaii	PUC	2011-0092	Consumer Advocate	2012	Operating Income, Rate Base, Cost of Service, Rate Design
Ameren Illinois Company	Illinois	ICC	12-0001	AG/AARP	2012	Alternative Regulation
Commonwealth Edison Company	Illinois	ICC	12-0321	AG	2012	Alternative Regulation
Ameren Illinois Company	Illinois	ICC	12-0293	AG	2012	Alternative Regulation
Ameren Missouri	Missouri	PSC	ER2012-0166	Industrials	2012	Income Taxes, Alternative Reg
Atmos Energy	Texas	RCT	10170	Municipals	2012	Operating Income, Rate Base
The Peoples Gas Light & Coke Company / North Shore Gas Company	Illinois	ICC	12-0511/0512	AG	2012	Operating Income, Rate Base
Ameren Illinois Company	Illinois	ICC	13-0192	AG	2013	Operating Income, Rate Base
Ameren Illinois Company	Illinois	ICC	13-0301	AG	2013	Alternative Regulation
Commonwealth Edison Company	Illinois	ICC	13-0318	AG	2013	Alternative Regulation
Commonwealth Edison Company	Illinois	ICC	13-0553	AG	2013	Alternative Regulation
Commonwealth Edison Company	Illinois	ICC	13-0589	AG	2014	Refund of Rider Revenues
Commonwealth Edison Company	Illinois	ICC	14-0312	AG	2014	Alternative Regulation
Ameren Illinois Company	Illinois	ICC	14-0317	AG	2014	Alternative Regulation
Southwestern Public Service Company	Texas	PUCT	43695	Municipals	2015	Operating Income, Rate Base
Ameren Missouri	Missouri	PSC	2014-0258	Industrials	2015	Income Taxes
Kansas City Power & Light Company	Missouri	PSC	2014-0370	Industrials	2015	Alternative Regulation, Taxes

Docket No. 160021-EI

AARP Exhibit MLB-1.3

(42 pages)

Future Test Years: Challenges Posed for State Utility Commissions

Ken Costello

Principal Researcher, Energy and Environment

National Regulatory Research Institute

Briefing Paper No. 13–08

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8611 Second Avenue, Suite 2C
Silver Spring, MD 20910
Tel: 301-588-5385
www.nrri.org

National Regulatory Research Institute

About the Author

Mr. Ken Costello is Principal Researcher, Energy and Environment, at the National Regulatory Research Institute. Mr. Costello previously worked for the Illinois Commerce Commission, the Argonne National Laboratory, Commonwealth Edison Company, and as an independent consultant. Mr. Costello has conducted extensive research and written widely on topics related to the energy industries and public utility regulation. His research has appeared in numerous books, technical reports and monographs, and scholarly and trade publications. Mr. Costello has also provided training and consulting services to several foreign countries. He received B.S. and M.A. degrees from Marquette University and completed two years of doctoral work at the University of Chicago.

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The author wishes to thank **Dr. Douglas Howe**, independent consultant; **Professor Douglas N. Jones**, The Ohio State University; **Bill Steele**, formerly of the Colorado Public Utilities Commission; and NRRI colleague **Dr. Rajnish Barua**. Any errors in the paper remain the responsibility of the author.

Executive Summary

Over the past several decades, public utilities have lobbied hard for changes in traditional rate-of-return (ROR) ratemaking when conditions arise that threaten their financial viability. More recently, they have gone before state legislatures and petitioned utility commissions for additional expedient cost recovery in the form of cost trackers, surcharges, revenue decoupling, and formula rates. On occasion, they have also pushed for a future test year (FTY) in determining rate changes. An FTY uses projections of costs and revenues, usually over a 12-month period during which new rates would apply, as the basis for rate changes. The selection of a test year can affect future rates. Depending on conditions, for example, an FTY can either reduce or increase rates over what they would be under a historical test year (HTY).

Understandably, utilities tend to endorse an FTY when it would increase their rates in a period of rising average cost and are silent during periods of declining costs. Utilities have stressed the adverse effects of regulatory lag and the need to file frequent rate cases in the face of rising average cost. Specifically, they contend that current market and operating conditions inevitably cause a utility's total costs to grow more than sales between rate cases, in the process eroding their earnings, a trend they find particularly worrisome in an era of large investments. Overall, utilities argue that the ratemaking paradigm needs to adapt to current conditions if regulation is to fairly compensate utility shareholders and serve the long-term interest of customers. One particular change advocated by utilities is the use of an FTY. An FTY usually covers the first 12 months when new rates would go into effect, or what some analysts call the "rate year" or "test period."

The reader might ask why a commission should rely on anything other than an FTY, since good ratemaking requires that new rates reflect the utility's costs and sales, at least over the first several months that they are in effect. Ratemaking, after all, is prospective, and an FTY matches the test year with the effective period of new rates. Although in theory this argument seems indisputable, it ignores the reality that forecasts are susceptible to error and some costs and sales elements are inherently difficult to predict. Another factor, as this paper stresses, is that utilities would have incentives to present biased forecasts that are not always easy for commission staff and interveners to uncover. A commission would be presumptuous to assume that forecasted costs and sales are more accurate than modified HTY data accounting for "known and measurable" changes. In fact, many commissions have taken this view, which seems sensible and in line with their mandate to set "just and reasonable" rates.

In sum, an environment of rising average cost does not constitute a sufficient condition for the use of an FTY. Supporters of an FTY give this false impression, which ignores the reality of utility forecasts being susceptible to bias and inherent error. Information asymmetry, which is an acute problem in public utility regulation, makes it difficult for commissions to evaluate a utility's forecasts in terms of their accuracy and objectivity.

Utilities contend that rising average cost requires an FTY for ratemaking if they are to have a reasonable opportunity to earn their authorized rate of return. They see shortening regulatory lag as essential for achieving this outcome. "Regulatory lag" refers to the time gap between when a utility undergoes a change in cost or sales levels and when the utility can reflect these changes in new rates. This gap has long been contentious within the regulatory arena in different contexts, with varying interpretations as to its positive and negative effects on utility customers and the public interest. Several state commissions view regulatory lag in a positive light by giving utilities greater incentive to manage their costs. Partly for this reason, they look more favorably upon HTYs than FTYs.

Although financially viable utilities is a regulatory goal, state utility commissions have a duty to take a broader and more balanced perspective by considering whether the use of an FTY would serve the public interest. What might best serve utility interest might violate the public interest. For example, utility over-collections between rate cases is a serious problem, especially when it leads to "exorbitant" actual rates of return for a number of consecutive years. Commissions should recognize that over-collections are just as troubling as under-collections.

Commissions should ask how an FTY would benefit utility customers. Commissions set rates using the "just and reasonable" standard as the primary goal. This standard recognizes the prominence of both utility financial viability and prudent utility operation. The utilities' one-sided view of FTYs gives little attention to this second aspect of good ratemaking. Utilities also underemphasize the role that management plays in affecting their rate of return. The fact that they are earning below their authorized rate of return may stem from less-than-optimal management practices.

This paper will first discuss the arguments for an FTY and why utilities have advocated it for ratemaking. It will then identify the major elements of an FTY and what challenges they pose for state utility commissions. The paper will look at, for example, what can go wrong if a commission is unable to sufficiently evaluate a utility's forecasts in rate cases. Although in theory an FTY seems appealing, its effect on the public interest hinges on a commission capability to meet the challenges that it presents. In other words, the merits of an FTY rest on the details of whether the forecasts (1) reflect prudent utility management and (2) contain a minimal margin of error. After all, if a utility makes poor forecasts, if a cost or sales element is susceptible to a potentially large forecasting error, or if the utility biases its forecasts that go undetected, an FTY could easily take money away from utility customers and give it to the utility and its shareholders. This paper shows that when the utility wants to avoid what analysts call a "ratchet effect," it could attempt to inflate its costs in line with its forecasts. Customers end up paying excessively for service while utility shareholders earn lower returns. In effect, this avoidance benefits utility management at the expense of two of its major stakeholders: customers and shareholders.

Finally, this paper suggests how commissions can execute an FTY to minimize problems that can harm utility customers. A fundamental, and perhaps the most serious, obstacle to this goal is information asymmetry that places commissions in a tough position to evaluate the reasonableness of a utility's forecasts. If commissions are unable to perform this evaluation—for example, because of deficient resources—utilities can charge higher rates that hurt the economic well-being of their customers.

Table of Contents

Future Test Years
Challenges Posed for State Utility Commissions

I. An Historical Perspective

Although traditional rate-of-return (ROR) procedures have dominated ratemaking for decades, state commissions have a history of adapting to a changing environment when doing so is in the public interest.[1] Take the example of the rising average cost of utility service, which started to emerge in the late 1960s. General inflation, oil price shocks, declining productivity growth, and stricter environmental standards were major factors leading to increases in electricity generating costs. Commissions were unable to include these cost increases in rates fast enough to prevent utility profits from falling. At the same time, utilities' sales growth started to decline in response to rising electricity prices and a slowdown in economic activity. Overall, electric utilities' earnings were eroding because of regulatory lag.[2] In response, many state commissions adopted fuel adjustments clauses, future test years, Construction Work in Progress (CWIP) in rate base, and new rate designs (e.g., marginal-cost pricing) to mitigate the problem.[3]

Over the past several years, both electric and gas utilities have continued to petition their state public utility commissions in addition to increasingly lobbying state legislatures for what they call "innovative ratemaking mechanisms" that deviate from traditional ratemaking practices.[4] In fact, one can go as far back as the late 1960s and early 1970s to see that utilities

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[1] *See* Douglas N. Jones, "Agency Transformation and State Public Utility Commissions," *Utilities Policy*, Vol. 14 (2006): 8-13; and Douglas N. Jones, "Regulatory Concepts, Propositions, and Doctrines: Casualties and Survivors," *Journal of Economic Issues*, Vol. 22, no. 4 (December 1988): 1089-1108.

[2] "Regulatory lag" refers to the time gap between when a utility undergoes a change in cost or sales levels and when the utility can reflect these changes in new rates.

[3] Other actions included hypothetical capital structures and a year-end rate base. Most utilities also can file for emergency rate relief anytime it encounters a serious financial problem; the commission could specify conditions for a utility to file an emergency or interim rate filing petitioning for immediate rate relief.

[4] Traditional ratemaking refers to the application of cost-of-service methods for setting rates that determine the utility's authorized of return. Features of this method include: (a) new rates remains fixed until the commission approves new rates after a comprehensive rate case; (b) the utility has a reasonable opportunity to earn its authorized rate of return; (c) rates only reflect prudent and efficient utility costs; (d) the balancing of utility customer and shareholder interests is an overriding goal; (e) the selected test year tries to matches revenues with costs over the first year of new rates; (f) the utility's actual rate of return between rate cases deviate from the authorized return because of unexpected movements in sales

also pushed for new ratemaking mechanisms to accommodate what they perceived as the changing market and operating environment. This time the new ratemaking mechanisms have encompassed a wider umbrella. Both electric and natural gas utilities in recent years, for example, have expanded their use of nontraditional ratemaking mechanisms to include different cost trackers for a large number of utility activities, revenue decoupling, formula rates, and surcharges for new investments.[5]

All of these mechanisms have resulted in the shifting of risk from utility shareholders to customers. In fact, these mechanisms collectively have accommodated utilities over time by giving them more financial security. But as some analysts have argued, these mechanisms have weakened the incentive of utilities to manage their operations and investments efficiently, in part because of the erosion of regulatory lag. These mechanisms may also jeopardize prudence reviews, which along with regulatory lag are arguably the most effective regulatory tools to motivate utility cost efficiency.

One mechanism that utilities have intermittently pushed for over the past 40 years is a future test year (FTY) for setting general rates. Utilities have exhibited "cherry picking" by pushing for FTYs when it favors their financial position; they did not lobby for FTYs when average cost was falling, as continuation of an historical test year (HTY) would bolster their financial position.[6]

Utilities favor FTYs under predictable conditions: slow sales growth, large new investments and, overall, rising average cost.[7] An increase in average cost means that, given a

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and costs; and (g) regulatory lag can either benefit or harm utilities, depending on whether average cost is decreasing or increasing.

[5] *See* Pacific Economics Group Research, *Alternative Regulation for Evolving Utility Challenges: An Updated Survey*, prepared for the Edison Electric Institute, January 2013 at http://www.eei.org/whatwedo/PublicPolicyAdvocacy/StateRegulation/Documents/innovative_regulation_survey.pdf. Cost trackers, for example, are a general category of devices that allow current recovery of costs in specified categories; revenue trackers compensate a utility for revenue losses between rate cases because of energy-efficiency programs and other factors (e.g., the price elasticity of demand).

[6] During the 1950s and 1960s, for example, the cost of generation, both because of scale economies and technological advances, declined and demand for electricity grew at a robust rate. Rate reviews were relatively infrequent and utilities consistently earned above their authorized rate of return.

[7] One way to define average cost is the price of inputs divided by total factor productivity (TFP). TFP in turn is the output divided by the input. Growth in TFP can originate from different sources, including technology advances, economies of scale, higher output, less waste of internal resources, and more efficient mix of inputs. Some of these factors fall within the control of utility management, while others fall outside. Mathematically, any increase in average cost results from the combined percentage increase in input prices and the level of inputs exceeding the percentage increase in output (*see* footnote 8). A slowdown of output growth along with inflation and new investments creates a condition of rising average cost. With price, or average revenue fixed between rate cases, an increase in average cost inevitably leads to the lowering of a utility's earnings or profits. This creates what analysts called

fixed price between rate cases, a utility's earnings will erode. By definition, average cost increases when total cost grows by a higher percentage than output or sales. Total cost, in turn, grows whenever the price of inputs used by a utility rises or the utility increases its inputs (e.g., labor, materials, physical capital). So three general factors affect average cost: changes in input prices, the level of inputs, and sales.[8] Some critics of an HTY, which has dominated state-commission ratemaking through the years, have argued that it is non-compensatory when the utility's average cost is higher in the rate year than in the historical test year, which could start as long as two years prior to the rate year (i.e., the first 12 months of new rates).[9]

II. The Current Status of Future Test Years

A. Trend toward FTYs

A recent survey noted that:

> Forward test years were adopted in many jurisdictions during the 1970s and 1980s when rapid price inflation and major plant additions coincided with slowing growth in average use…Several additional states have recently moved in the direction of FTYs. Many of these states are in the West, where comparatively rapid economic growth has required more rapid build out of utility infrastructure. FTYs were recently sanctioned legislatively in Pennsylvania.[10]

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earnings attrition. Conversely, in an environment where a utility's productivity is growing rapidly and inflation is low, a utility's earnings is likely to increase between rate cases above the authorized rate of return set in the last rate case.

[8] Specifically, average cost increases when the combined growth in input prices and levels exceeds the growth in sales. Under a condition of moderate to high inflation, large investments in new facilities and slow sales growth, average cost would likely rise. Average cost equals total cost divided by the output level (Total cost, in turn, equals the sum of the product of input prices and input levels.) Rearranging terms, average cost (AC) equals:

AC = price of inputs/total factor productivity

Thus, % ΔAC equals % Δ price of inputs minus % Δ total factor productivity, or % Δ price of inputs plus % Δ inputs minus % Δ output. As an example, if input prices increase by an average three percent, input levels by one percent and output by two percent, average cost would rise by two percent.

[9] These critics, utilities, have included Wall Street, consultants working for industry and some economists.

[10] Pacific Economics Group Research LLC, *Alternative Regulation for Evolving Utility Challenges: An Updated Survey*, prepared for the Edison Electric Institute, January 2013, 29 at http://www.eei.org/whatwedo/PublicPolicyAdvocacy/StateRegulation/Documents/innovative_regulation_survey.pdf. Since this survey, Indiana has allowed utilities to use an FTY.

The survey shows that 23 states allow or require commissions to use an FTY for ratemaking, at least for electric utilities.[11] In addition to Pennsylvania, recent states that have allowed an FTY include Indiana and New Mexico. Over half of the states now allow the use of a test year other than historical, and this number has grown over time.[12]

B. Continued commission opposition to FTYs

How many additional states will allow or require FTYs over the next several years is hard to predict. The research for this paper has shown that many commissions hold FTYs in deep contempt. It seems unlikely that they will switch to an FTY in setting rates unless forced to by their legislatures. A past order by the Public Service Commission of Utah exemplifies why many parties have a negative disposition toward FTYs:

> Our concerns with future test periods include the diminished economic examination and accountability, replacement of actual results of operations data with difficult-to-analyze projections, ability of parties to effectively analyze the Company's forecasts, dampening of the efficiency incentive of regulatory lag, playing to the Company's strength from control of critical information, and shifting of the risks of the future to ratepayers.[13]

In the past ten years, some commissions have studied different test years and decided against the use of an FTY. One such commission is the Iowa Utilities Board. In a 2004 report to the state's General Assembly, the Board concluded that:

> [The] implementation of the future test-year option would significantly increase costs of ratemaking during the transition and probably in the long-term. It also finds use of a future test year over the current hybrid approach will not necessarily provide rates that more accurately reflect a utility's cost of providing service.

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[11] State statutes, rules, and practices have laid out three distinct conditions for use of an FTY: (a) the commission must use an FTY, (b) the commission must use an FTY if the utility proposes one (e.g., Michigan, Minnesota), and (c) the commission has the discretion to choose a test year, including an historical, future or hybrid (several states). The last condition allows the commission to weigh the evidence in deciding on what test year the utility should use. Although it gives the commission flexibility to decide on a case-by-case basis, the downside is that the time parties need to present their arguments and for the commission to rule might reduce scrutiny of other important issues in a rate case.

[12] A 2009 survey conducted by the NARUC Subcommittee on Accounts, with only 20 state utility commissions responding, showed that 6o percent used an HTY with "known and measurable" changes of state utility commissions, 35 percent used either an HTY or FTY and 5 percent only used an FTY.

[13] Public Service Commission of Utah, *In the Matter of the Application of PacifiCorp for approval of Its Proposed Electric Service Schedules and Electric Service Regulations, Order Approving Test Period Stipulation*, Docket No. 04-035-42, 3, October 20, 2004.

Iowa's hybrid approach allows for consideration of evidence outside the historical test year. [14]

In Nevada, a report to the state's legislatures by the Public Utilities Commission recommended:

> …the hybrid test period for its energy utilities that starts with the most recent 12-month historical date and adjusts all major costs of service elements for reasonably known and measurable data through the rate effective period. The Commission believes this hybrid test period has more advantages than either the fully forecasted methodology or the more restrictive hybrid methodology, which adjusts for 7-months of data…this hybrid approach leverages the existing ratemaking methodology, providing consumers, regulated utilities and the regulatory community with more consistency than the fully forecasted test year methodology.[15]

As with many other commissions, the Washington Utilities and Transportation Commission relies on a modified historical test year. The commission believes that this approach avoids the problems with an FTY while also recognizing the need to adjust historical data. As articulated in a recent rate case:

> [I]n Washington, we use a modified historic test year approach. We start with audited results from a recent 12 month period, but we modify those results to reflect changes that substantial evidence, timely presented, shows have occurred during the pendency of a rate case, or will occur in the rate year that begins at the conclusion of the proceeding…*This approach reduces regulatory lag without burdening ratepayers with unnecessary costs determined on the basis of the more speculative future test year approach to ratemaking that is used in some jurisdictions.* Our approach strikes a balance that motivates…utilities subject to our jurisdiction to carefully manage their costs and revenues going forward and take full advantage of their opportunity to recover fully all fixed and variable costs including a reasonable return on capital investments.[16] [Emphasis added]

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[14] Iowa Utilities Board, *Review of Utility Ratemaking Procedures*, Report to the Iowa General Assembly, January 2004, 13 at http://www.state.ia.us/iub/docs/reports/noi032_FinalReport.pdf.). The Board added that it can consider capital investments in service within nine months after the end of the test year for rate base inclusion.

[15] Public Utilities Commission of Nevada, *Report to the 74th Session of the Nevada Legislature: Alternatives to the Historical Test Year Methodology for Setting Public Utility Rates in Nevada*, May 10, 2006, 17.

[16] Washington Utilities and Transportation Commission, *Order 11, Docket UE-090704 and UG-090705*, April 2, 2010, 11 at http://www.utc.wa.gov/docs/Pages/DocketLookup.aspx?FilingID=090704.

A modified HTY adjusts historical data for unreasonable and non-recurring costs and sales in addition to accounting for expected changes in the future (i.e., "known and measurable" changes). As with an FTY, the intent is to reflect cost and sales conditions expected for the period of new rates. Many commissions implicitly consider a modified HTY to satisfy the "balancing act" by making adjustments to mitigate regulatory lag while protecting customers from paying for "speculative" costs.

This paper addresses whether the continued resistance to an FTY reflects what some critics of commissions would describe as "status quo bias" or, instead, a rational position given the risks, especially to utility customers, associated with an FTY.[17] Utilities and Wall Street tend to criticize commissions for not changing to an FTY. As discussed in this paper, these critics have a credibility gap in advancing FTYs as supporting the public good, since they take a clearly narrow and biased perspective on FTYs that downplays the negatives. As discussed later, these negatives have the effect of redistributing economic welfare from customers to utilities.

III. Different Test Years and Regulatory Lag

A. Sources of regulatory lag

How does the selection of a test year affect regulatory lag? A test year is an actual or hypothetical 12-month period over which a utility calculates its costs, including both operating and capital costs, and revenues to determine the need for a rate change.[18] At the core of a test year is the "matching principle" for achieving consistency between costs and revenues. The utility would thus consider jointly revenue requirements and billing determinants in setting new rates.

Regulatory lag can be understood as the period between the beginning of the test year and the starting period for new rates. If the HTY is the calendar 2012, for example, and new rates do

[17] "Status quo bias" refers to a situation in which a commission would stick with its current practices and policies even if change would better serve the public interest. Some analysts would label this behavior bureaucratic inertia.

[18] In determining the required revenue change, the commission compares the revenue requirement and revenues under present rates. Specifically, revenue deficiency equals

$$RR_{ty} – GR_{pr}$$

RR_{ty} equals the test-year determined revenue requirement, and GR_{pr} equals the gross revenues under present rates. If the utility expects a shortfall in revenues to meet its revenue requirement, it might decide to file for a rate increase.

not go into effect until January 2014, the lag would be 24 months.[19] In the context of this paper, regulatory lag is the time between a test year and the rate year.

Four events encompass regulatory lag:

1. The utility recognizes the need for new rates—for example, because of earnings erosion caused by costs rising faster then revenues.[20]

2. The utility prepares and files a rate case.

3. The commission conducts hearings and issues a decision.

4. New rates go into effect.

The time between events (1) and (3) can extend longer than one year, depending on the preparation time for filing new rates and the length of a rate case. Assuming that it takes a utility four months to prepare a rate case and the rate case itself lasts nine months, the time duration would be 13 months. Say that the utility sees its cost increasing and earnings eroding in October 2012. It promptly prepares a rate case and files with the commission in February 2013. The commission makes a decision in November 2013. The new rates do not take effect until January 2014.

B. Three kinds of test years

There are three general groupings of test years (*see* Figure 1). Using our previous example, an historical test year would be 2012, in which the utility would have actual data for the 12-month period. An HTY uses data for a 12-month period that ends prior to a rate filing. A partially future or hybrid test year could cover the last six months of 2012 and the first six months of 2013.[21] A future test year could be the calendar year 2014.

For the historical test year, the new rates starting in 2014 depend on cost and demand conditions in 2012. If these conditions change between the two years, the new rates could create

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[19] January 2012 is the beginning of the test year and the starting point for the new rates is January 2014.

[20] Attrition or erosion refers to the tendency for a utility's rate of return or profits to fall since the last rate case. On the opposite side of the spectrum is the term accretion, which refers to a utility "overearning" between rate cases.

[21] Minnesota is a state that relies heavily on a partial future test year. The FTY usually starts when interim rates go into effect, which is within 60 days of a utility's rate filing. One rationalization for defining the test year this way is that it differs little from an HTY adjusted for "known and measurable" changes.

a gap between the authorized and actual rate of return.[22] When using an historical test year, the utility usually normalizes and annualizes its costs and sales[23]; it may also make adjustments for "known and measurable" changes.[24] These last two actions convert the raw HTY data to be more representative of the conditions during the effective period of the new rates (i.e., the rate year or, as some call it, the test period). These adjustments would tend to increase the likelihood that the utility would earn its authorized rate of return.[25]

The partially future or hybrid test year would mitigate regulatory lag when compared with the HTY, as the new rates would account for conditions in the first half of 2013, which is closer in time to when the new rates go into effect.[26] Actually, although at the outset of the rate case the utility presents six months of forecasts, as the case progresses the utility might substitute actual data for some of its forecasts. For example, the commission could allow the utility to use actual data for the first four months of 2013. The test year would then represent 10 months of actual data and two months of forecasts.[27]

The future test year, in its purest form, forecasts all the costs and sales elements for the first 12 months of new rates. An FTY, therefore, begins after a rate case and normally at the time when new rates would go into effect.[28]

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[22] This discrepancy mostly affects equity holders, as revenue shortfalls cut into the utility's rate of return on equity. On the other hand, changing conditions could make the HTY favorable to the utility and its shareholders. For example, sales could increase enough to more than offset any inflation and new investments.

[23] The utility would normalize weather for projecting sales; it could also normalize rate case expenses and storm damage. An annualization adjustment would involve, say, a wage increase in effect for only five months to cover the entire HTY.

[24] These changes can include those that have already taken place after the end of the HTY or changes that are likely to happen in the near future (which is more contentious and speculative). For the latter, usually the commission would require a high probability of occurrence.

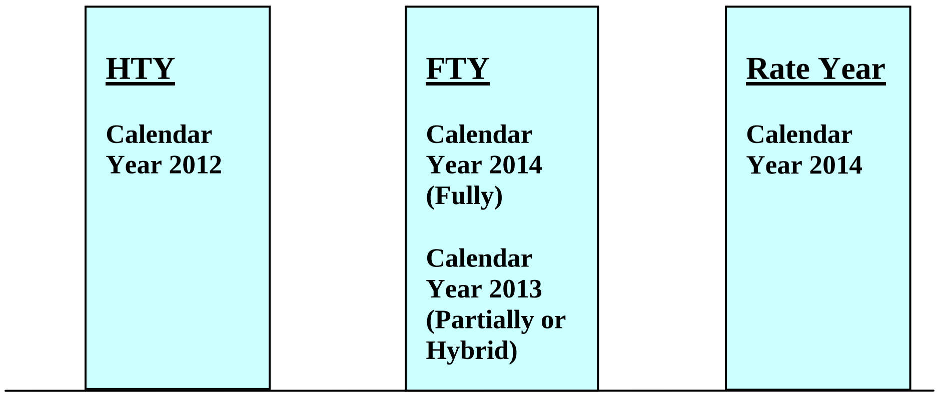
[25] These adjustments are arguably the most contentious aspect of HTYs.

[26] Some analysts refer to them as a rolling test year; for example, a test year that always takes 3 quarters of actual data and 3 months of forecasts.

[27] Unlike a FTY, the hybrid test year ends prior to the effective date of new rates.

[28] In a different sense, an FTY can begin after the period of the latest available actual data for costs and sales.

Figure 1: Different Test Years (Rate Case Filed in Early 2013)



IV. Framing the Issue: Two Different Perspectives

A. Utility/investor perspective

Utility management and their investors understandably place primary consideration on the effect of a test year on the utility's finances. They view regulatory lag in an era of increasing costs and slowing sales growth as detrimental to their interests.[29] Utilities contend, for example, that regulatory lag can limit their ability to raise capital for new investments and to remain financially viable. As expressed on the website of the National Association of Water Companies (NAWC):

> In a rising-cost industry with heavy capital investment requirements, the use of historic test years assures there will be no return on or recovery of capital that is invested during the test year and thereafter until the utility files another rate case. Any return on such investments could therefore be delayed for a number of years. This discourages necessary investment during these periods and skews construction and investment timing based on artificial test year issues rather than system needs and efficient construction planning processes. Due to regulatory lag, strictly historical test years can virtually ensure that the utility does not earn its allowed rate of return, thereby increasing risk and the cost of capital.[30]

In various forums, utilities and their investors have argued that an FTY would:

[29] Compared to the late 1960s and early 1970s, current conditions of low inflation and interest rates have helped to control utilities' average cost, making the argument for FTYs less tenable.

[30] C:\My Documents\Rate Design\NAWC Prospectively Relevant Test Year.mht. The link contains a table of the test years used in the 50 states and the District of Columbia for water utilities.

1. *Avoid earnings shortfalls from regulatory lag.* Utilities point to the divergence between the authorized and actual rate of return as a measure of excessive regulatory lag; they contend that during a period of rising average cost, a commission should use an FTY to set new rates; otherwise, they are unlikely to have a reasonable opportunity to earn their authorized rate of return.

2. *Support new investments, especially by shortening the lag time for recovering the costs for new facilities.* Otherwise, a utility may have to file rate cases more frequently just to get new facilities into rate base.

3. *Give customers better price signals by setting rates that are more closely aligned with a utility's actual costs during the effective rate period.*

4. Since the future is unlike the past because of economic and operational changes, historical data, even with piecemeal adjustments, *give a false sense of accuracy*.[31]

As will be discussed later in this paper, many state commissions believe that regulatory lag provides an important incentive for efficient utilities operations. There is no clear answer to the question of optimal regulatory lag.[32] Several commissions are also leery of the accuracy of forecasts and their manipulation by utilities to support higher rate increases, matters that this paper addresses later.

B. Broader public-interest perspective

The task for commissions is to translate stakeholders' interest into the public or more general interest. This is an essential feature of the "balancing act" of regulation in which commissions try to avoid certain outcomes, notably excessive rates and suppression of utility investors. FTYs are definitely beneficial to utilities and their investors. Why else would they propose them, other than to reduce the risk of earnings shortfalls? The relevant question for commissions is how an FTY would promote the interest of utility customers. The answer is not so obvious, as this paper argues.

The "balancing act" often uncovers the extreme positions of parties, whether they are utilities or interveners. It requires commissions to make trade-offs between various ratemaking objectives in reaching an outcome that best serves the general public. For example, although an

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[31] Similarly, as discussed later, a false impression occurs when presuming that when the utility directly forecasts costs and sales over the period of new rates, those forecasts would accurately represent future conditions.

[32] When the utility initiates rate reviews, it is in a position to manipulate the regulatory process to its advantage. Yet if reviews occur at fixed intervals, such as under a price-cap regime, the utility would have an incentive to inflate costs just prior to a review so as to receive higher rates in the following period.

FTY could help the utility financially, it may expose customers to the risks of forecasting error and bias.

Listening to Wall Street and utility investors gives the impression that commissions are the sole reason for utilities not earning their authorized rate of return. They tend not to blame management when utilities lose customers or allow the efficiency of their operations to deteriorate. Instead, investors expect commissions to compensate utilities even when utility management is at fault. Specifically, they want commissions to grant utilities prompt and guaranteed cost recovery.[33]

For FTYs, utilities like to emphasize the benefits while downplaying the negatives. They tend to overstate the ease with which a commission and other parties can evaluate their forecasts.[34] They place primary focus on the financial effect of ratemaking practices. Consumer groups often concentrate on the negatives of FTYs while slighting their benefits. They tend to unequivocally reject FTYs in principle, while actual conditions may sometimes justify them.[35] The job of commissions is to sift through the conflicting evidence in approving "just and reasonable" rates.

Commission rejection of an FTY may be more of a rational response than inertia. Inertia implies a rigid commission position toward an FTY, no matter the circumstance or what the evidence shows (i.e., status quo bias, in which the commission sticks with an HTY no matter the environment or expected outcome). It seems more plausible that rejection of an FTY reflects the reluctance of a risk-averse commission to accept a mechanism with uncertain outcomes that could make matters worse. Some commissions find the evidence for an FTY to be speculative, inconclusive, and biased.[36] Even if exaggerated, this perception reflects a common belief among both commissioners and staff that using an FTY could lead to an undesirable outcome, irrespective of the utility's costs, demand, and operating conditions.

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[33] *See*, for example, Chairman Mark Sievers, "Wall Street Meets Main Street: The Regulator's View," presentation at the Mid-America Regulatory Conference, June 11, 2013, 9 at http://www.marc2013.com/CLE/SieversWall%20Street%20Meets%20Main%20Street.pdf.

[34] Utilities give the false impression that they do not have much of an advantage over other parties in understanding their operations and what constitutes efficient management. To the contrary, they have a pronounced advantage over other parties that makes evaluating the utility forecasts such a difficult task.

[35] These conditions include capability of parties to review a utility's forecasts, the absence of ratemaking mechanisms to allow a utility to recover costs between rate cases (e.g., cost trackers, infrastructure surcharges, revenue decoupling) and rapidly rising average cost.

[36] Poor forecasts are the product of ignorance, bias, or a combination of both.

1. Achieving "just and reasonable" rates

The acceptability of a test year depends on its ability to produce outcomes compatible with the standards underlying "just and reasonable" rates. The test year provides a foundation for determining such rates.

Legal precedent dictates that commissions must set reasonable rates that allow a prudent utility to operate successfully, maintain its financial integrity, attract capital, and compensate its investors in line with actual risks.[37] The emphasis is then on the results reached, not on the methods used. One obvious implication is that the appropriate test year depends on its likelihood of leading to "just and reasonable" rates.

"Just and reasonable" rates have two primary traits. First, rates should reflect the costs of an efficient and prudent utility. Second, rates allow a prudent utility a reasonable opportunity to receive sufficient revenues to attract new capital and not encounter serious financial problems. The first condition prevents customers from paying for costs that the utility could have avoided with efficient or prudent management. In using an FTY, excessive costs can also include "phantom" expenditures that the utility forecasts and that are included in rates but are not actually incurred. Commissions attempt to protect customers from excess utility costs in part by scrutinizing a utility's costs in a rate case.

A prudent utility should have a fair chance of earning its authorized rate of return. Yet this condition does not guarantee that the utility will earn close to or at its authorized rate of return. Part of the reason why a utility may experience earnings shortfalls is management's inability to control costs. Under traditional ratemaking practices, the commission normally does not allow a utility to make up any lost profits, which would constitute retroactive ratemaking.[38]

If commissions want to guarantee that the utility will recover its authorized earnings, they would favor a rate design that allows the utility to recover all of its fixed costs in a monthly service charge or a customer charge.[39] Since generally commissions do not, they implicitly recognize the positive incentive effect from allowing a utility's actual rate of return to deviate from the authorized level. Commissions also know that if a utility is continuously earning below its authorized rate of return, the utility can always file a general rate increase.

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[37] The U.S. Supreme Court outlined these conditions in its 1944 order for *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 605 (1944).

[38] Variants of traditional ratemaking, such as formula rate plans, are not retroactive because the regulator does not look back to alter past rates, but instead provides notice that future rates will be adjusted pursuant to a specific formula.

[39] Such a rate design would not guarantee the utility earning its authorized rate of return, as unexpected variable costs would cause the utility's earnings to decline.

2. The positive side of regulatory lag

Economic theory predicts that the longer the regulatory lag, the more incentive a utility has to control its costs; when a utility incurs costs, the longer it has to wait to recover those costs, the lower its earnings are in the interim. The utility, consequently, would have an incentive to minimize additional costs. As economist and regulator Alfred Kahn once remarked:

> Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses, and offers rewards for their opposites; companies can for a time keep the higher profits they reap from a superior performance and have to suffer the losses from a poor one.[40]

Commissions rely on regulatory lag as an effective tool for motivating utilities to act efficiently. Specifically, they view it as essential to limit risk shifting to utility customers from utility "mistakes."

Regulatory lag is a less-than-ideal method, however, for rewarding an efficient, and penalizing an inefficient, utility. Some of the additional costs could fall outside the control of a utility (e.g., increase in the price of materials), and any cost declines might not correlate with a more managerially efficient utility (e.g., deflationary conditions in the general economy). As discussed elsewhere in this paper, commissions are more receptive to an FTY when (1) regulatory lag causes a substantial downward movement in a utility's rate of return between rate cases, and (2) the utility has displayed good forecasting capability, as evidenced by its past track record.

3. Relevant policy questions

Commissions should ask what test year would best produce "just and reasonable" rates, in addition to other regulatory objectives. Specifically, what conditions would most support a specific test year? Is the preferred test year sensitive to an individual utility's operating and market conditions? The preferred test year hinges on several factors. They include:

1. *The ability of the commission to validate the accuracy and reasonableness of cost and revenue projections.* Some commissions might have to augment their staff expertise by hiring more economists and forecasters to review utility projections; commissions need a different skill set in reviewing an FTY filing versus an HTY filing.

2. *The increased cost and complexity of rate cases that an FTY would cause, net of the expected decrease in the frequency of rate cases over time, especially in a period of rising average cost.*

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[40] Alfred E. Kahn, *Economics of Regulation, Vol. 2* (New York: John Wiley & Sons, 1971), 48.

3. *The perceived fairness of customers prepaying for utility activities before they occur*; that is, the utility recovering costs before they are incurred or for activities that may not happen (i.e., "phantom" activities).[41]

4. *The trade-off between the accuracy of historical data and their representativeness for the test period*. Historical data, even when adjusted, might poorly reflect conditions over the period of new rates; accurate forecasts compatible with prudent costs for a future period, however, are difficult for utilities to produce, and even harder for commissions to evaluate.

5. *A dynamic environment in which the future is unlike the past and might deviate substantially from the past in terms of utility cost, operating, and demand conditions*.

6. *Overall, the test year that provides a better picture of the actual conditions a utility will face over the period of new rates.*

V. Basic Elements of a Future Test Year

A. Difference from a modified historical test year

The comprehensive nature of an FTY makes it distinct from a modified HTY. Every cost and revenue item requires a forecast. As proponents of an FTY have argued, an HTY, even when adjusted for "known and measurable" changes, may poorly represent actual conditions during the period of new rates. It may require a utility, for example, to rely on growth in sales, economies of scale, and productivity gains to avoid "earnings" erosion until it files the next rate case.

An FTY makes it more difficult for commission staff and other parties to review a utility's rate filing. It requires evaluating all the utility's cost subaccounts and revenue categories with enough skill and resources to make a valid judgment.

B. Matching revenues with costs

Two core features of a test year are (1) that the calculations of revenues, expenses, and rate base occur over the same time period and (2) the presence of consistency among the different costs and sales elements. The latter requires, for example, that the variable-cost[42]

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[41] One prime example is customers paying for a new generating facility before it begins operation. The utility might include the plant in rate base using, for example, a 2014 test year. The expectation is that the utility will start operating the plant in 2014. The plant may get delayed to 2015, but the utility in the meantime received approval to start recovering its cost in 2014.

[42] Variable costs are costs that vary with the level of sales or output.

forecasts are compatible with the sales forecasts and that operating costs account for new facilities added to the rate base.

One problem with adjusting an HTY for "known and measurable" changes is that the utility could make adjustments to some costs or revenue[43] components but not others because they are either difficult to measure or speculative in nature. As an example, completion of a new facility is imminent, so it receives test-year inclusion, but any savings in system operating cost or increase in revenues generated by the facility may get excluded. The utility's filing in this example violates the "matching principle" and would tend to support an excessive rate increase.

C. Should commissions prefer price caps?

One might then ask whether commissions should view price caps as an alternative to ROR regulation using an FTY. A generic price-cap formula contains a specified price index (PI) from which a productivity measure (X) is subtracted:

$$\%\Delta P = \%\Delta\ PI - \%\Delta\ X,$$

The allowed percentage increase in price ($\%\Delta$ P) equals the percentage increase in some specified price index ($\%\Delta$ PI) minus the percentage increase in productivity ($\%\Delta$ X).[44] Productivity growth, for example, could reflect the average historical gains for a peer group of utilities. It could measure technological improvements for an industry or for the economy as a whole. The price index could encompass a broad range of commodities that are either regional or national in scope. One possible choice is the Consumer Price Index.

Unlike ROR regulation using a FTY, price caps rely on cost and productivity estimates for the industry or at least not directly for an individual utility. A utility could then profit from keeping changes in its costs below the industry average. Whereas under ROR regulation the utility uses itself as the benchmark, price caps include a benchmark exogenous to the control of an individual utility.

Under price caps, the utility has strong incentives to grow sales and manage costs. Price caps compared to ROR regulation, at least in theory, promote cost efficiency because price adjustments do not reflect changes in a utility's cost, and rate reviews take place at predetermined

[43] Revenue issues include utility versus non-utility operating revenues, weather adjustments, off-system power and gas sales, contracts, promotional and other discount rates, unbilled revenues (billing lags), imputed revenues, deferred revenues, and sales growth forecasts.

[44] See, for example, Paul L. Joskow and Richard Schmalensee. "Incentive Regulation for Electric Utilities," *Yale Journal on Regulation*, Vol. 4, No.1 (Fall 1986): 1-49.

multiyear intervals prescribed by regulators.[45] Price caps should, therefore, provide utilities with stronger incentives when prices relate to cost factors outside the control of an individual utility, and regulators do not readjust the price-cap formula whenever a utility is earning above-normal (or below-normal) profits or for some arbitrary reason.[46]

A problem with price caps is that a utility's earning might fluctuate to extreme levels. Commissions tend to frown upon utilities' earning a "high" rate of return. More generally, they also might feel uncomfortable about a ratemaking mechanism that accommodates a wide range of utility profits.

D. Filing requirements

1. Essential information

Commissions should require at least three things from utilities that propose an FTY: (1) documentation, (2) supporting analyses, and (3) assumptions. Utilities should file these items at the same time they submit their FTY rate request.[47]

Utilities should provide complete documentation to allow a thorough review by commission staff and interveners of the forecasting methodology, data sources, assumptions, and the past forecasting record of the utility. These parties should have access to transparent information from the utility that allows them to understand and verify the forecasts. Only then can a commission rule on the validity of the utility's forecasts in setting new rates.[48]

Utilities should link their projections with historical data to provide a "bridge." Otherwise, the utility would find it easier to hide costs from commission staff and interveners. The utility should provide at least three years of historical data, with more years preferred for recognizing trends and better judging the utility's forecasts.

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[45] In effect, prices caps have commission-determined regulatory lag; for example, once the commission sets base rates in a rate case, the utility cannot file another rate case for five years. Under ROR regulation, utilities control the timing of rate cases.

[46] As a rule, the "ratchet effect" would affect utility behavior under price caps any time it expects current benefits of increased efficiency to be "taken away" in the form of lower future prices. If so, utility incentives to control costs would converge toward those under ROR regulation.

[47] The utilities should file their data in executable electronic format.

[48] One question relates to whether the commission should allow a utility to file confidential data in support of its FTY. What is a reasonable standard for which the commission should grant confidentiality on future projected data? It could allow confidentiality of some data with good cause but not enough to jeopardize transparency, which is so important in reviewing a utility's rate proposal.

2. An example of utility modeling

If the utility used a statistical (e.g., econometric) method for forecasting,[49] the utility should provide the commission with various information. First, the utility should explain the theoretical construct of the model: What were the reasons for choosing the predictors specified in the model? Why did the utility choose a linear, quadratic, or other functional model for the model?

Second, the utility should provide the entirety of the data used in estimating the model. Regulatory staff might want to replicate the results by re-estimating the model with actual data used by the utility. Third, the utility should document the statistical procedures used and their rationales. Fourth, the utility should document the underlying assumptions of the predictors used in the model (e.g., price in a sales model). What did the utility assume, for example, about economic growth and inflation rates for materials? As expressed by the noted statistician, Nate Silver:

> When we make a forecast, we have a choice among many different methods…The way to become more objective is to recognize the influence that our assumptions play in our forecasts and to question ourselves about them…You will need to learn how to express—and quantify—the uncertainty in your predictions. You will need to update your forecast as facts and circumstances change.[50]

Finally, the utility should demonstrate the forecasting ability of its model. How well did the model forecast past costs or sales, assuming that the utility knew the values of the predictors?[51] In this example, any forecasting error would result from how the utility specified and estimated the model, rather than from making wrong assumptions about the predictors.

In sum, any of the above factors could affect the forecasts and would be difficult to rebut by other parties. The utility could simulate a model several times and present in a rate filing the result that most favors its position (e.g., the forecast that shows the lowest sales growth). Although parties could dispute the forecast, they may find it hard to argue the superiority of an alternate forecast. The utility, for example, might use a quadratic model because it forecasts the lowest sales growth while a linear model would show a higher growth, but the choice is not easy for other parties to defend as more valid.

For many items forecasts are not robust, in that they are highly sensitive to future scenarios of the world. Electricity sales for next year depend on economic conditions, price,

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[49] Some utilities apply econometrics methods to forecast sales and selective cost components.

[50] Nate Silver, *The Signal and the Noise: Why So Many Predictions Fail—But Some Don't* (New York: The Penguin Press, 2012), 72-3.

[51] *See* Part VI.D.2 for a more detailed discussion.

weather, and energy-efficiency behavior. Arguments over the numerical value for each predictor—and how it affects electricity sales—would be contentious and time consuming in a rate case. More important, the commission has the tricky task of selecting what it considers the most accurate single-point forecast. Basing a decision solely on a single-point or "best guess" forecast is risky. Usually in different contexts it is valid only when (1) the decision maker places a high degree of confidence in a single-point forecast, and (2) the consequences of an incorrect forecast are small.

A key question for commissions is whether forecasts from a model or other methodologies are sufficiently accurate for setting rates. For sales and large cost components, the forecasting error in percentage terms could be small and still have a non-trivial effect on the utility's earnings. Supporters of an FTY emphasize the deficiency of an HTY to accurately represent costs and revenues in the rate year. There is no guarantee, however, that forecasting them over the same period would produce more accurate results. Forecasters, as a general matter, tend to overstate the accuracy of their predictions even when those predictions are based on sound techniques. When adding the "bias" element inherent in a utility's forecasts (discussed later), one can easily imagine why an FTY might fail to better represent the utility's cost, operating and other conditions over the rate year.

One last point is that commissions should subject outside forecasts produced by reputable firms to the same scrutiny they would apply to a utility-produced forecast. They cannot take for granted that a forecast produced by an outside firm is sound and objective. The firm might have a reputation for producing results that favor a utility or other clients' positions in regulatory and other venues.

VI. Specific Challenges for State Commissions

A report by the NARUC Staff Subcommittee on Accounting and Finance laid out the basic questions on test years that commissions need to address:

> Whether using a future or historic test year, the auditor should judge the appropriateness of the test year that has been proposed. Is it representative, after adjustments, of the period in which rates take effect? …When looking at a future test year, one will want to examine the test year selected for reasonableness. Is this period mandated by rules, statute, or Commission directive? Is the test year founded on a historical base or documented figures, such that its projections are readily understandable and traceable?[52]

Below are the major challenges of FTYs for commissions. Although they should not automatically disqualify the use of FTYs for ratemaking, they do pose special problems that

[52] NARUC Staff Subcommittee on Accounting and Finance, *Rate Case and Audit Manual*, Summer 2003, 10 at http://www.ipu.msu.edu/library/pdfs/NARUC%20Ratecase%20Audit%20Manual.pdf.

commissions need to address carefully. If commissions do not, an FTY could harm utility customers.

A. Information asymmetry

The core problem with FTYs for commissions is information asymmetry. Commissions are at a distinct disadvantage relative to the utility in interpreting and evaluating the utility's performance. Commissions generally lack the knowledge, for example, to detect when the utility is efficient or inefficient, and the opportunities for utilities to minimize their costs. As part of their duties, they need to evaluate whether the utility's projected costs reflect competent utility management, or imprudent management. A utility naturally would argue that its projections reflect its best effort given the conditions it faces.[53] To rebut this claim, commission staff and interveners would need to provide evidence to the contrary. They can show, for example, the invalidity of some assumptions or forecasting methodologies that underlie their predictions.

One basic question centers on who has the burden of proof in providing information in support of its position. Assume that a utility proposes an FTY. Should the utility have the duty to show that using an FTY rather than a modified HTY would more likely produce "just and reasonable" rates? Or should other parties have the burden to show that a modified HTY would produce more socially desirable rates? Who has the burden of proof could influence the commission's decision. A persuasive argument for placing the burden on a utility is that it possesses superior expertise in accessing and interpreting relevant information. Efficiency and "fairness" considerations, along with the general principles of law, suggest that the party with the best access to information should have the burden of proof. For example, a utility should back up its claim of superiority of an FTY over other test years. Of course, commissions should exercise caution in interpreting information originating from one party with definite self-interest motivations.[54] That is why parties have to scrutinize the utility's filing and frequently supplement it with information from other sources. The commission would be well-advised to have as its mantra "Don't trust and do verify."

Although the utility may have the burden to demonstrate the reasonableness of its predictions, any proposed adjustments by other parties would require an evaluation showing the predictions' shortcomings. The utility has a big advantage over other parties in knowing its prudent costs. It is hard for commission staff and interveners to either (1) show that the utility's costs are excessive or (2) produce independent forecasts that reflect efficient utility management. For the commission, it comes down to a judgment call in determining the appropriate cost for an FTY. Probably the truth lies somewhere between the utility's high forecasts and the interveners' low forecasts.

[53] Some utilities might want to give the impression that they have little control over certain costs or that whatever control they might have, they have done their best in managing.

[54] As a rule, commissions should apply caution in interpreting information that is asymmetrical, insufficient, and uncertain.

B. Acceptable format for data submittal

Commissions should require utilities to present certain data in a format that allows other parties to review it without great difficulty. Good examples of comprehensive and standard data-filing requirements are Illinois[55], New Mexico[56] and Wisconsin.[57]

In presenting its forecasts, a utility should file sufficient documentation to permit a thorough review by the commission and non-utility stakeholders of the forecasting methodology, data sources, assumptions for the predictors, and the past forecasting record of the utility.[58] Only then can the commission judge the validity of the forecasts. If the utility used a model for forecasting a specific cost or sales element, the utility should demonstrate the forecasting ability of its model. How well did the model, for example, forecast in the past?

C. Compatibility of rate-base treatment of new projects with the "used and useful" test

FTYs pose a special problem for commissions in regard to how they should address unexpected delays, cost overruns, and even cancellation of new facilities. If the utility's forecast turns out to be overly optimistic, customers may end up paying for new facilities prior to in-service status. As an example, a commission may approve a 2014 test year that included costs for a new electric transmission facility expected to be in service by June of that year. Assume that the facility encounters delays that set a new expected completion date of early 2015. Customers are then paying for the facility without receiving any benefits from it. This prepayment might not pose a problem in states that allow, for example, CWIP in rate base, but for other states it would. Can we then conclude that an FTY is not permissible in the latter states, or that they need to give special treatment to new facilities?

Take the example of a "used and useful" state (i.e., a state that allows a utility cost recovery only after a facility is in service and benefiting its customers) where a utility expects a new facility to come into service part way through the test period. In avoiding the situation described above, the commission could:

- Exclude the facility as part of the revenue requirement calculation in the rate case, and

[55] *See* http://www.icc.illinois.gov/docket/files.aspx?no=02-0509&docId=51197.

[56] *See* http://www.nmcpr.state.nm.us/nmac/parts/title17/17.001.0003.htm.

[57] *See* Wisconsin Public Service Commission, "Investor Owned Utility Rate Cases Data Submittal Requirements Request for Change in Rates," Commission staff correspondence, April 6, 1995

[58] *See* the discussion in Part V.D.2.

- Only add it into rates when the facility comes on line and the commission determines its costs to be prudent in a separate proceeding.

This approach is not reliant on the construction-completion date and the cost projections; it also does not require customers to prepay for the facility prior to its in-service date. Finally, this approach also would reduce regulatory lag by allowing the utility to start recovering its costs prior to filing a new rate case. If the utility operated under an HTY, for example, the utility would have to file a new rate case before recovering any of the costs for a new facility completed outside the test year. Exceptions are when the utility has a special surcharge or tracker that allows it to recover costs in the absence of a general rate case.[59]

D. Checking for the accuracy of past forecasts

1. Three commission actions

Commissions can do three things. They can require utilities to measure the accuracy of their past forecasts. Commissions can then compare the actual costs and revenues with what the utility forecasted during the previous rate cases.[60] If a utility applied a model to derive these forecasts, it should identify the different causes of forecast errors. To what extent were errors the result of (1) wrong assumptions for specific predictors or (2) model estimation errors? The legitimacy of applying the same model to predict the future partially depends on the model's historical forecasting performance.

A commission can also view whether forecast errors occurred predominantly in one direction: Were cost forecasts consistently high or sales forecasts consistently low? Finally, a commission can rely on past forecasting errors as a guide to set a tolerance level for using an FTY. If past forecasts exhibited large errors, a commission might want to consider alternatives to using an FTY for setting future rates. Consistently biased and faulty forecasts can provide support, for example, for reverting to an HTY adjusted for "known and measurable" changes.

2. One measure of forecasting accuracy

One simple measure of forecasting accuracy *ex post facto* is to compare the actual outcomes with the forecasts. This is expressed mathematically as:

$$E_t = C_t^a - C_t^e$$

[59] A commission may consider appropriate a so-called negative tracker or rider in the event customers are paying for a new plant that unexpectedly encountered delays in completion and thus not providing them with any benefits. The rider, which would involve the utility crediting customers, could continue until the time that the plant actually goes into service. I thank Bill Steele for this thought.

[60] Analysts refer to any discrepancies as *ex post* forecasting variances.

E_t is the forecast error for year t, C_t^a is the actual outcome (say) for a cost element for year t, and C_t^e is the forecast for year t.[61] Forecast errors measured with historical data provide an indicator of a model's past performance. A measurement of forecast error can also apply to forecasts from utility budgets or other procedures. Generically, forecast errors provide a track record of a utility's past performance in forecasting individual cost and revenue components. They can identify forecast bias and whether the utility has performed better or worse over time. Has the utility, for example, improved its forecasting ability during the past two years relative to earlier years?

Forecast errors can offer a guide to the model's future forecasting performance. But often they will understate the error because of market and other dynamics that could jeopardize the forecasting accuracy of the model for future periods.[62]

Calculating forecast errors for several years can reveal whether the utility was consistently biased in one direction. The caveat is that a utility might intentionally inflate its actual costs to align with its forecast. As discussed later, a utility may seek self-fulfilled prophecy to avoid the consequences of the "ratchet effect."

When outcomes vary from the forecasts, the commission should distinguish between two causes: faulty forecasts, and unexpected events that a prudent forecast could not have accounted for. From an analytical perspective, the objective should be to minimize forecast error by creating the best possible forecast; for example, producing unbiased forecasts from a sound statistical model. Commissions should require utilities to forecast with valid methods and verifiable data. This standard requires that utilities apply generally acceptable statistical and modeling techniques. If utilities fall short in meeting it, commissions should reject their forecasts or at least question the forecasting method.

Finally, forecasting errors from models can result from mistaken assumptions and the wrong theory. The wrong theory might result in model misspecification with important predictors excluded. The underlying theory might predict, for example, that natural gas sales depend on the wrong factors or ignore certain factors that are important. If, for example, general economic conditions play an important role in affecting sales, ignoring this factor could produce biased forecasts that would systematically over- or under-forecast sales for a future test year.

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[61] Variants of this measure express the error in percentage terms or as a root mean square error over several periods.

[62] An estimated model may have good statistical properties from applying historical data, but perform poorly in forecasting. One explanation is that a structural change in the electricity or natural gas market could make the historical relationships between cost or sales and their predictors irrelevant for forecasting the future. One example involves the future availability of new energy-efficiency hardware, which could make consumers more responsive to increased prices in the future than historically.

E. Determining criteria for judging forecasts

Before its evaluation, a commission should consider drafting guidelines on criteria for judging forecasts: Should sales forecasts rely on generally acceptable modeling and statistical techniques? What factors should a utility consider in forecasting sales and costs? What inflation index should it use? How will a commission assess the reasonableness of the assumptions underlying the forecasts?

F. Limited time to evaluate utility projections

Utilities have a distinct "resource" advantage over other parties that they can better exploit under an FTY rate filing. Given the limited time for rate cases and the complexity of evaluating forecasts, parties may have insufficient time to thoroughly assess a utility's forecasts.

One possible outcome is the utility hiding inflated costs and not "getting caught." Utilities would (1) have an incentive to overstate its costs, as discussed elsewhere in this paper and (2) vigorously challenge other parties who propose to adjust the costs downward.

G. Updating revenues and costs during a rate case

As part of guidelines, a commission can lay out criteria for updating the utility's filing during a rate case. These criteria can apply to all test years, whether historical or future in nature: For an HTY, updates would make actual costs and sales more current; updates for an FTY would involve using more current data to revise forecasts; if, for example, the utility used a statistical model for forecasting, it could add more data points to re-estimate the model.

The commission may want to limit updates to major developments. Any updates should give other parties adequate time to review them. If a utility proposes a partial FTY, the more updating the commission allows the more the test year becomes historical in nature.

H. Are less-than-perfect forecasts more representative of the future than historical conditions?

This question lies at the crux of selecting the appropriate test year. As argued earlier, if the utility has a poor track record of forecasting, an HTY, even with all of its flaws, might be preferred. A utility should lose the opportunity to use an FTY, for example, if previous forecasts turned out grossly wrong and the utility earned exorbitant returns.

I. Utility incentive for misreporting costs and revenues

Commissions observe forecasts but not the effort or competence of utility management, except for crude measures (e.g., labor costs, plant availability); utilities have the information edge, knowing their own effort, output and skill level; this asymmetry makes it difficult to distinguish between forecasts reflecting prudent and imprudent costs.

1. Three questions

- **Why would a utility be more inclined to overstate costs than to understate costs?** The utility expects the commission to lower its cost forecasts, so it would tend to initially file inflated costs.[63] There is little payback for a utility that hedges on the low side. The likelihood of the utility's actual costs being higher would increase, thus jeopardizing its rate of return and penalizing shareholders.

- **How serious is this problem?** It depends on the ability of a utility to get away with reporting inflated costs. For example, the utility might ask for recovery of costs in a rate case no matter how frivolous or unlikely they are. It has little to lose if the commission catches it (except for the credibility of future forecasts); if the commission approves the cost, the utility recovers "phantom" or imprudent costs. The result is that the utility's customers are paying excessively for utility service.

- **How can a commission detect overstating of costs?** It can observe any systematic bias in past forecasts. For example, it may detect constant overforecasting of a certain cost item for a number of years. The only way for a commission to uncover inflated costs, although admittedly imperfect, is to do a thorough review of the assumptions, methodologies and other factors underlying the forecasts. This activity requires a commission staff with adequate resources and skills. It also subtracts time from other crucial rate-case matters that could lead to ill-informed decisions.

2. The "ratchet effect"

a. Definition and conventional view

The "ratchet effect" involves the commission's adjusting future forecasts based on past forecasting errors. The commission observes the utility's actual costs *ex post* to reset a future price. The "ratchet effect" reflects dynamic strategic behavior that analysts often ignore in comprehending the actions of public utilities and their regulators.

One conceivable utility response to regulatory lag is to reduce costs during the initial years after new rates and increase costs right before the next rate review. The latter action could justify a higher future rate, while the former action could allow the utility to retain the cost savings during most of the time between rate cases. For example, the utility might try to fool the commission into thinking that it is a high-cost utility so that it can charge higher rates in the future.

An argument made by FTY proponents is that the "ratchet effect" reduces the incentive of a utility to overstate forecasted costs in a rate case. Since the interaction between the utility

[63] Conceivably, a commission's downward adjustment of a utility's forecasts could leave the utility in no better position than under an HTY.

and commission is a repeated game, the commission can learn more about the accuracy of a utility's forecasts over time as it (1) observes the utility's actual costs and (2) compares them with the forecasts filed in previous rate cases; thus, the utility would acquire a reputation for its ability to forecast. Gross bias, for example, could damage the utility's credibility. Another possible check on utility misreporting is other parties' monitoring the utility's forecasts.[64]

Traditional ratemaking would then seem to "penalize" a utility for overstating its costs or understating its sales in a future rate case. For example, assume that a utility has an incentive to overstate its costs for an FTY. To the extent that it can misreport its expectation of the true cost, the utility can earn, without taking any incremental actions, an above-normal ROR without the commission knowing it until a later time. The commission at some future time could apprehend this strategic behavior and, in effect, transfer the excess earnings in the next rate case to the utility's customers.

b. An illustration of utility avoidance of a "ratchet effect"

Using a simple equation to more formally illustrate the previous discussion, the net gain to a utility from misreporting estimated costs is,

$$NG_u = (c^r - c^e) - b\cdot(c^r - c^e)$$

$$= (c^r - c^e)\cdot(1-b)$$

The net gain to the utility, NG_u, equals the difference between reported costs (c^r) to the commission and the utility's expected costs (c^e), minus the proportion (b) of the misreporting level (c^r-c^e) that the commission deducts from the utility's forecasted costs in the next rate case.

As the value of "b" approaches one, the ratchet effect strengthens: The utility suffers from misreporting in previous periods by being granted lower rates in the future. In the extreme case where "b" equals one, a utility's overreporting of cost in an earlier period (thereby increasing its rates) is fully offset by lower rates in later periods. The utility would benefit marginally, since its discount rate is greater than zero. Thus regulatory lag provides the utility with some incentive to control costs, even with a "ratchet effect." The commission would presumably look at a utility's costs and deduct from them the amount that the utility overforecasted in a prior period.

Alternatively, the utility could avoid a "ratchet effect" by intentionally inflating its costs right before a new rate case to close the gap between its forecasted and actual costs. In other words, a utility may initially overforecast its costs in the last rate case and then make sure that actual costs do not fall far below them.

An example is a utility projecting costs of $110 million but knowing that with efficient management it can achieve a cost of $100 million. Assume that the commission allows the $110

[64] This action assumes that other parties have the capability to detect misreporting.

million for setting new rates. If the utility achieves $100 million, which the utility could easily do, its shareholders would benefit from a higher rate of return. But the utility might conclude that in the next rate case the commission would adjust its cost forecasts because it overestimated its previous cost by 10 percent. To avoid this "ratchet effect," the utility might decide to allow its costs to attain closer to or at the $110 million level.[65] The end result is that (1) utility management would have excess money to spend, funded by its customers, and (2) shareholders would earn close to their authorized ROR because management prefers to spend the excess money rather than giving the money back to shareholders in the short run. This behavior seems more rational if one presumes the importance of utilities' retaining credibility with their past forecasts for future rate cases. If utilities are high with their cost forecasts a few times or even once, understandably they may believe that the commission would more likely adjust downward their forecasts in the future. On the margin, a utility may decide that inflating costs to lessen forecasting error is in its best long-term interest.

J. Utility incentive for efficient operation

Whether using an historical or future test year, a utility retains (at least until the next rate case) every dollar that is saved: By lowering its input prices or improving its overall cost efficiency (e.g., productivity), a utility actually would earn a higher rate of return until the commission "takes it away." The commission might do this by implicitly setting a higher productivity target in the next rate case to account for improved efficiency gains in the preceding periods. The "ratchet effect"—namely, lower costs today translate into lower rates in the future—dilutes a utility's incentive to improve its efficiency: The utility would receive no benefits beyond the next rate case when the regulator reflects past improvements in future rates. Knowing this possibility, a utility subject to ROR regulation (no matter the test year) would have an incentive to inflate its costs shortly before the next rate case.

As discussed in the last section, FTYs can have a negative effect on cost efficiency. One reason is self-fulfilling predictions to avoid a "ratchet effect." Another possible reason lies with imputing in an FTY expected cost increases yet to be determined. A utility, for example, might have a weaker incentive to negotiate wage increases below the amount already included in rates. A third reason lies with information asymmetry, in which a commission would find it difficult to identify imprudent costs in a utility's rate filing. As such, the threat of disallowed costs lessens and thereby removes an important tool for commissions to control a utility's costs. Overall, an FTY would seem to score poorly in achieving cost efficiency.

K. FTYs and utility risk

Historically, commissions have approved cost trackers, revenue decoupling, and infrastructure surcharges to avoid earnings erosion because of unforeseen or immeasurable events at the time of the last rate case. The argument for these out-of-rate-case mechanisms is

[65] By our assumption, this cost level would reflect utility inefficiency, since it is $10 million above the level that the utility knows it could achieve with prudent management.

strongest when a commission relies on a historical test year that disregards expected developments during the rate year. Assume that a certain operating cost has trended upward (e.g., 2 percent per year) over the past several years. Assume also that the commission allows only a historical test year. In this example, the utility is likely to under-recover this cost item. What effect this outcome would have on the utility's overall rate of return depends on (1) the magnitude of any cost increase relative to the utility's earnings and (2) whether other costs fell while new rates were in effect.

As a practice, commissions do not expect utilities to earn exactly their authorized rate of return during each future period over which new rates are in effect.[66] Commissions implicitly impute a risk premium in the authorized rate of return, partially to account for volatility in earnings from unexpected fluctuations in costs or revenues. Out-of-rate-case mechanisms intend to mitigate business risk. "Business risk" refers to the uncertainty linked to the operating cash flows of a business. Business risk is multi-dimensional, inclusive of sales, cost, and operating risks. Both commissions and utility management can affect business risk.

To the extent that an FTY better projects costs and sales for future periods, as argued by FTY proponents, it should improve a utility's financial condition (e.g., interest coverage, credit rating) and lower its risk.[67] If so, should not a commission contemplate lowering the utility's authorized rate of return?[68] After all, FTYs do not decrease overall risk; instead, they shift risk from utility shareholders to customers. At least, that is the utilities' intent, as they would tend to overstate their costs and understate their revenues under current rates. Although utilities would have a similar incentive under an HTY, their ability to avoid misreporting detection would be greater under an FTY. One reason is that utilities can more easily hide "inflated costs" when making forecasts rather than reporting their actual costs, which are subject to strict audits. When a utility makes a false report of its actual costs, it can suffer a severe sanction. No such penalty occurs when the utility makes an inaccurate forecast.

[66] This statement supports the contention that commissions do not intend the prices they set in a rate case to reflect a utility's actual cost of service for each future year. Commissions, however, judge that the prices they approve will allow the utility an opportunity (i.e., a reasonable chance) to earn its authorized rate of return or some return within a specified "dead band."

[67] *See*, for example, Mark Newton Lowry et al., *Forward Test Years for U.S. Electric Utilities*, prepared for the Edison Electric Institute, August 2010, 49-52 at http://www.eei.org/whatwedo/PublicPolicyAdvocacy/StateRegulation/Documents/EEI_Report%20Final_2.pdf.

[68] How much commissions should lower the authorized rate of return is a difficult question. By shifting risk from utility shareholders to customers and decreasing the risk of under-recovery, an FTY should reduce the utility's cost of capital. In other words, an FTY should reduce the risk premium that prospective investors place on a utility.

L. Bridging historical data with forecasts

As part of standard reporting in rate cases, commissions should require a utility to provide a verifiable link or bridge between an historical and future test year as a point of reference.[69] Without this benchmark, parties reviewing a utility's filing would lack essential information for judging the validity of the forecasts. They would find it difficult, for example, to understand the foundation or basis for the forecasts.

M. Identifying the preferred forecasting approach

The preferred approach for forecasting depends on the traits of individual costs and revenues elements. For some costs, assuming no change or a change based on recent trends or on inflation indices could be appropriate. A utility using these simple methods should justify their use and the assumptions underlying them. For other cost items, a more sophisticated approach, such as statistical modeling, might produce better forecasts.[70] Below are six general approaches for forecasting:

1. **Inflation factor:** Global Insight, for example, forecasts inflation rates for labor, materials and services used by utilities; it also provides price indexes for detailed O&M expenses itemized in the Uniform System of Accounts. A utility might also use some macro inflation index, such as the GDP Implicit Price Index. The assumption is that a particular cost item will grow only because of inflation, with no change in labor, materials or other resources.

2. **Change in both activity level and inflation:** The change in cost component "i" (e.g., administration expenses) can equal $\Delta Cost_i = \Delta Activity_i \cdot \Delta Cost\ per\ Activity_i$, which depends on both the change in activities and the inflation rate for labor and other inputs. In evaluating a cost change, commission staff and interveners should review the utility assumptions about the inflation rate and change in activity levels, with each quantified and properly supported. If the utility assumes more maintenance activities, for example, it should explain the reason and measure the effect on cost.[71]

[69] The historical test year can represent the base year. One definition of the base year is the most recent calendar year for which the utility had information in preparing its rate case.

[70] These models can include time-series models that produce price forecasts based on past values of price; and econometric models that relate cost or sales to variables (i.e., predictors) that explain their movements over time. Statisticians refer to time-series models as *autoregressive models*. In an autoregressive model, a cost or sales component in the current period represents a weighted average of past observations of the same component going back several periods, plus a random disturbance in the current period. *See*, for example, Robert S. Pindyck and Daniel L. Rubinfeld, *Econometric Models and Economic Forecasts* (New York: McGraw-Hill Book Company, 1976), 458.

[71] Utilities will often forecast their O&M costs based on budget data. Some analysts consider budgets "wish lists" and not best-guess cost estimates for specific utility functions. Budgets may not

3. **Historical average:** If a cost or revenue component displays erratic behavior, the best approach might be to use a multi-year (e.g., three-to-five-years) average rather than assigning a high weight to the latest observation.

4. **Modeling:** For some cost and sales components, accurate forecasts require an analytical framework with good predictive capability and data.

5. **Trends:** A trend is the persistent tendency of a cost or sales element to move in one direction, either upward or downward; if sales exhibit a linear trend, it is then growing or shrinking at a constant rate over time. Detecting trends require observations over a number of years.[72] Some analysts argue that five years of historical data is the minimum for recognizing past trends.

6. **No change:** The latest observation is appropriate, assuming no expected change in the cost or sales element. The utility might expect, for example, wages to remain constant over the rate year or the price of postage stamps to stay the same.

Rather than evaluating the utility's forecasts, commission staff and interveners might want to derive their own forecasts. They will find this approach costly and subject to tough cross-examination and rebuttal by the utility if their forecasts differ greatly from the utility's and support a lower rate increase than what the utility proposes.

N. The risk associated with selecting the wrong test year

Applying the wrong test year can lead to either excessive or deficient rates:

- Using an FTY when the market environment is stable may lead to excessive rates because of forecasting error and utility gaming (i.e., biased projections). Some costs and sales elements are inherently difficult to forecasts even just for a year ahead.

- An HTY can produce deficient rates when utility total cost is rising faster than sales, causing a utility's rates to fall below its average cost.

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always align with sales or other costs, violating the "matching principle" that is essential for a test year. For example, if a utility develops a budget for each function separately and not jointly with other budgets, inconsistency among different budget items may result.

[72] What is the relationship, for example, between sales in a historical context and expected sales during the period of new rates? Assume that natural gas sales (in therms) over the last five years are as follows: 15 million, 16 million, 14 million, 13.5 million, and 17.5 million. What sales level is representative of expected sales over the period of new rates? What factors should a utility consider? What are the major determinants of sales? Do past sales reflect a trend or a cyclical pattern? Does the recent high growth in sales indicate robust growth over the next few years?

In either instance, utility rates would not satisfy the "just and reasonable" standard that most commissions define for ratemaking. How a commission decides on the test year hinges on its risk aversion toward selecting the wrong test year and its interpretation of the available information.[73] Would a commission more disfavor excessive or deficient rates? Which test year would estimate the most accurate costs and sales over the test period or the first 12 months of new rates?

Decision making under uncertainty sometimes accounts for what analysts call *Type I* and *Type II* errors (*see* Table 1). Errors in the context of test years relate partially to how much a utility's actual ROR deviates from its authorized ROR. In deciding on the appropriate test year, a Type I error can cause a dead-weight loss from excessively high rates, as the utility captures more of the economic welfare gain (i.e., of the otherwise consumer surplus[74]) from sales. The utility also might have the incentive to realize its inflated-cost forecast (i.e., cost inefficiency) to avoid a "ratchet effect" (as discussed earlier) and lost credibility of its forecasting capability in future rate cases. Another possible adverse outcome is the utility earning excessive returns because of biased projections not detectable by commission staff or interveners.

A Type II error can lead to a utility not investing in facilities and undertaking other actions that would benefit customers in the long run. The utility might encounter serious financial difficulties because of rates lagging behind costs. The utility sees its credit rating drop, it suffers cash-flow problems, and its actual rate of return is (say) at least 100 basis points below its authorized return. These outcomes depend on the availability of other ratemaking mechanisms to mitigate regulatory lag, such as cost trackers and revenue decoupling.

Because utilities assign a high cost to a Type II error, their preference is for a FTY. In contrast, because consumer groups would tend to place a high value on avoiding a Type I error,

[73] One commission, the Public Service Commission of Utah, identified eight factors for selecting a test year. They are: (a) the general inflation rate; (b) changes in the utility's investments, revenues or expenses; (c) changes in utility services; (d) the availability of accurate data to non-utility parties; (e) the ability to match the utility's investments, revenues, and expenses; (f) whether the utility's costs are increasing or decreasing; (g) incentives to efficient management; and (h) the expected length of time for new rates. (Public Service Commission of Utah, *In the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations, Order Approving Test Period Stipulation*, Docket No. 04-035-42, October 20, 2004.)

[74] *Consumer surplus* is the difference between the value that consumers place on a good or service and the amount that they actually pay. Technically, consumer surplus is the area under the demand curve and above the price. When customers pay a higher utility rate, their consumer surplus decreases by the sum of (a) the loss in net benefits from less consumption and (b) the additional payment for consuming at the actual level compared with what they would have paid at the same consumption level under a lower rate. When the higher rate is above the utility's prudent costs, it results in what economists call a "deadweight loss" (i.e., aggregate economic-welfare loss).

their preference is for an HTY.[75] A commission must trade off the two types of error in reaching a decision: Reducing one type of error compromises the other. For example, in reducing the risk from an FTY (Type I error), the commission takes the chance in selecting an HTY that produces deficient rates and financial problems for the utility.

If a commission views the two errors in terms of an excessively high or low ROR, it might want to consider an earnings-sharing plan or what some analysts call a *formula rate plan*. A formula rate plan is a ratemaking method in which the utility adjusts periodically (e.g., annually) its base rates without a general rate case, conditioned on an actual ROR on equity that falls outside some commission-defined band. The band might encompass, for example, 100 basis points above and below the ROR on equity authorized by the commission in the last rate case.[76]

Table 1: The Risk of Choosing the Wrong Test Year

Test year	**Actual risk**	
	Stable conditions	*Dynamic conditions*
Future	***Type I error***	Preferred
Historical	Preferred	***Type II error***

[75] This observation is consistent with the prevalent opposition by consumer groups to an FTY, evident in their position and testimony in rate cases.

[76] Supporters argue that these plans help stabilize a utility's rate of return without a full-blown rate case review, thereby avoiding serious financial problems and preventing excess profits. Opponents argue that they shift risk to customers and give utilities weak, or even distorted, incentives to manage their costs.

VII. Recommendations for State Utility Commissions

Those commissions studying or applying FTYs for ratemaking might want to keep the following points in mind:

1. **The merits of an FTY depend on the availability of other ratemaking mechanisms that mitigate regulatory lag.**
   These mechanisms include CWIP in rate base, revenue decoupling, trackers, surcharges and formula rates.[77] Should a commission consider an FTY as a first or last resort for mitigating regulatory lag?[78] When a commission allows adjustment mechanisms triggering cost recovery between rate cases to protect the utility from unpredictable costs, sales, and other outcomes, an FTY has less justification as a ratemaking tool for utilities.

2. **Commissions should not underestimate the challenges of information asymmetry as it relates to FTYs.**
   A seminal economics article on the market for "lemons" (i.e., defective products) concludes that in markets plagued by information asymmetry, the market player holding an information advantage will likely dominate the outcome at the expense of others. For an FTY, the implication is that any outcome would be favorable to the utility in achieving higher profits or other goals that are harmful to its customers.[79] Information asymmetry reflects the relatively little knowledge that a commission has on the relationship between forecasted costs and utility-management competence. When a utility files a cost forecast, how does the commission know whether it reflects competent management? The analyst or auditor can evaluate the forecast applying state-of-the-art techniques; still, a level of uncertainty remains that leaves unknown the utility's level of competence embedded in the forecast. Supporters of an FTY seem to understate the seriousness of information asymmetry. States with large commission staffs might also not regard information asymmetry as a major problem, but smaller commissions and consumer groups would undoubtedly have a different view.

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[77] A primary intent of these mechanisms is to mitigate risks to utilities from bad projections for test-year costs and revenues.

[78] This paper makes no judgment on the superiority of any one mechanism in reducing regulatory lag. Each has its advantages and disadvantages, making it difficult to rank them based on their capability to best advance the public interest.

[79] George A. Akerlof, "The Market for 'Lemons': Quality Uncertainty and the Market Mechanism," *The Quarterly Journal of Economics*, Vol. 84, No. 3 (August 1970): 488-500.

3. **Commissions may want to consider developing a rule or policy statement.** They can specify conditions for acceptability of an FTY filing. A commission can prescribe a standard format or a set of minimum requirements for presenting FTY data. This mandate would help parties to facilitate the interpretation and evaluation of the utility's forecasts.

4. **Commissions could hold a technical conference or workshop.** This recommendation is especially relevant for states allowing or requiring an FTY for the first time. An FTY involves myriad technical issues that parties should try to resolve prior to rate cases. (The Appendix contains a list of questions that address the major issues.) Otherwise, rate cases themselves will involve their resolution, which deducts from the time for covering other rate-case matters. The commission will inevitably suffer through a "learning curve" before reaching a comfort level with FTYs.

5. **Commissions may want to look closely at the incentives that an FTY provides utilities for reporting their costs and sales.** In avoiding a "ratchet effect," a utility might inflate its costs to align its forecasted and actual costs. The consequence is customers overpaying for utility service and the utility's credibility maintained because of its apparent "reasonable forecasts." Since an FTY weakens the incentive effect of regulatory lag in addition to making it more difficult for commissions to exclude imprudent costs in rates, cost inefficiency is more likely to occur. Utility customers inevitably shoulder the excessive costs in the form of higher rates.

6. **Commissions should understand that applying forecasting methods for setting rates places a higher premium on accuracy than for other applications.** Commissions should consider demanding a small tolerable margin of error for costs and sales forecasts.[80] For example, the utility's projecting a sales increase of 0.5 percent when the actual increase was 1.5 percent could have a significant effect on its rate of return. A commission might ask whether it can rely on costs and sales forecasts for setting "just and reasonable" rates when accuracy is so important, as alleged by critics of an HTY. Often forecasters in different contexts express their predictions as a range of values within which an event (e.g., future sales) has a high probability of occurring. The uncertainty of predicating costs and sales gives theoretical support for commissions to look at a range of possible future scenarios, rather than focusing only on the most probable future state (i.e., the "best guess" forecast). In other words, for different decisions commissions should not put all of their faith in one forecast, even if that forecast is superior to all other forecasts. Yet in setting rates, commissions have no choice but to select a single forecast, knowing with almost absolute certainty that it will

[80] Assume that a utility inflates its costs by 3 percent and that its profits or margins are 20 percent of costs. The utility's margins or ROR would increase by 15 percent. If the authorized ROR on equity is 10 percent, the actual ROR would increase to 11.5 percent.

contain a margin of error. In some instances, forecasts are no more than an educated guess, which makes them especially suspect for setting rates. The policy question ultimately reduces to: Are forecasts sufficiently accurate for use in setting rates that are unlikely to result in an "extreme" rate of return, especially on the high side?

7. **Commissions will need to decide whether (a) they should rule at the beginning of a rate case the appropriate test year or (b) utilities should have the discretion to select a test year.**
   One view is that commissions should have the discretion to choose the test year, assuming they have the authority. The preferred test year from a public-interest perspective depends on the actual conditions facing a utility.[81] Why should commissions allow the utility to select the test year when they should expect a utility to choose one that best advances its interest rather than the public interest? What happens, for example, if a utility proposes an FTY and the commission staff, along with interveners, believes it is incapable of evaluating the forecasts? In this instance, the utility has a distinct incentive to inflate its costs and hopes that the commission would not detect them. This utility prerogative is akin to allowing the utility to choose rate design or a cost-of-service methodology, with the commission relegated to a secondary role in fine-tuning the proposals. Most commissions would understandably find this status unacceptable. Legislatures threaten the independence of state commissions when they mandate the use of a specific test year, no matter the circumstances or actual conditions faced by a utility

8. **Commissions may want to select a test year in individual cases based on a risk-based framework.**
   The preferred commission decision comes down to its risk aversion toward negative outcomes, given the available information. Some parties might have more concern with the possibility of using an FTY under stable conditions and risking excessive rates—what we previously called a Type I error. Other parties (namely, utilities and their investors) might assign a high risk to using an HTY under dynamic conditions—what we previously called a Type II error. Consistent with the "balancing act" feature of regulation, a commission must inevitably weigh the different outcomes in selecting a test year for the public good.

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[81] For example, *Section 54-4-4(3) of the Utah Code Annotated* states:

> If in the commission's determination of just and reasonable rates the commission uses a test period, the commission shall select a test period that, on the basis of evidence, the commission finds best reflects the conditions that a public utility will encounter during the period when the rates determined by the commission will be in effect.

The commission must then consider which test year would better represent future conditions over the rate year. For example, when it expects a utility's average cost to increase and deems the utility's forecasts to be reasonably accurate, an FTY would seem more appropriate than an HTY.

Appendix: Questions to Ask about Future Test Years

State utility commissions should ask several questions about FTYs, a simple concept, but as examined in this paper, posing tough challenges for state public utility commissions. The questions include:

1. Does the use of an FTY motivate utilities to overstate costs and understate revenues under present rates? If so, how can a commission address this problem?

2. Does an FTY advance the "balancing act" aspect of public utility regulation? Does it, for example, unduly favor utilities at the expense of their customers?

3. What conditions should hold to justify the use of an FTY?

4. What are the risks associated with using the wrong test year?

5. Can utilities manipulate their costs and revenue forecasts to inflate rates with unlikely detection by the commission and interveners?

6. What incentive does a utility have under different test years to control costs between rate cases?

7. Does an FTY improve a utility's financial condition to justify a lower authorized rate of return?

8. What rules should a commission have on forecast updates?

9. Does the commission have adequate staff resources to adequately evaluate utility forecasts?

10. How can a commission know the reasonableness of a utility's forecasts?

11. What is the level of forecasting errors that a commission should tolerate?

12. Who should bear the consequences of large forecasting errors?

13. How can a commission evaluate past forecasts to guide future forecasts?

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Docket No. 160021-EI

AARP Exhibit MLB-1.4

(9 pages)

Edison Electric
INSTITUTE

Rate Case Summary

Q1 2016
FINANCIAL UPDATE

QUARTERLY REPORT
OF THE U.S. INVESTOR-OWNED
ELECTRIC UTILITY INDUSTRY

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Contact:
Mark Agnew
Director, Financial Analysis
(202) 508-5049, magnew@eei.org

Bill Pfister
Manager, Financial Analysis
(202) 508-5531, bpfister@eei.org

Michael Buckley
Financial Analyst
(202) 508-5614, mbuckley@eei.org

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Edison Electric Institute
701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
202-508-5000
www.eei.org

The 51 U.S. Investor-Owned Electric Utilities

The companies listed below all serve a regulated distribution territory. Other utilities, such as transmission provider ITC Holdings, are not shown below because they do not serve a regulated distribution territory. However, their financial information is included in relevant EEI data sets, such as transmission-related construction spending.

ALLETE, Inc. (ALE)
Alliant Energy Corporation (LNT)
Ameren Corporation (AEE)
American Electric Power Company, Inc. (AEP)
AVANGRID, Inc. (AGR)
Avista Corporation (AVA)
Berkshire Hathaway Energy
Black Hills Corporation (BKH)
CenterPoint Energy, Inc. (CNP)
Cleco Corporation (CNL)
CMS Energy Corporation (CMS)
Consolidated Edison, Inc. (ED)
Dominion Resources, Inc. (D)
DPL, Inc.
DTE Energy Company (DTE)
Duke Energy Corporation (DUK)
Edison International (EIX)
El Paso Electric Company (EE)
Empire District Electric Company (EDE)
Energy Future Holdings Corp.
Entergy Corporation (ETR)
Eversource Energy (ES)
Exelon Corporation (EXC)
FirstEnergy Corp. (FE)
Great Plains Energy Incorporated (GXP)
Hawaiian Electric Industries, Inc. (HE)
IDACORP, Inc. (IDA)
IPALCO Enterprises, Inc.
MDU Resources Group, Inc. (MDU)
MGE Energy, Inc. (MGEE)
NextEra Energy, Inc. (NEE)
NiSource Inc. (NI)
NorthWestern Corporation (NWE)
OGE Energy Corp. (OGE)
Otter Tail Corporation (OTTR)
PG&E Corporation (PCG)
Pinnacle West Capital Corporation (PNW)
PNM Resources, Inc. (PNM)
Portland General Electric Company (POR)
PPL Corporation (PPL)
Public Service Enterprise Group Inc. (PEG)
Puget Energy, Inc.
SCANA Corporation (SCG)
Sempra Energy (SRE)
Southern Company (SO)
TECO Energy, Inc. (TE)
Unitil Corporation (UTL)
Vectren Corporation (VVC)
WEC Energy Group, Inc. (WEC)
Westar Energy, Inc. (WR)
Xcel Energy, Inc. (XEL)

Companies Listed by Category
(as of 03/31/2016)

Please refer to the Quarterly Financial Updates webpage for previous years' lists.

Given the diversity of utility holding company corporate strategies, no single company categorization approach will be useful for all EEI members and utility industry analysts. Never-the-less, we believe the following classification provides an informative framework for tracking financial trends and the capital markets' response to business strategies as companies depart from the traditional regulated utility model.

Regulated	80%+ of total assets are regulated
Mostly Regulated	50% to 80% of total assets are regulated
Diversified	Less than 50% of total assets are regulated

Categorization of the 46 publicly traded utility holding companies is based on year-end business segmentation data presented in 10Ks, supplemented by discussions with company IR departments. Categorization of the five non-publicly traded companies (*shown in italics*) is based on estimates derived from FERC Form 1 data and information provided by parent company IR departments.

The EEI Finance and Accounting Division continues to evaluate our approach to company categorization and business segmentation. In addition, we can produce customized categorization and peer group analyses in response to member company requests. We welcome comments, suggestions and feedback from EEI member companies and the financial community.

Regulated (37 of 51)

Alliant Energy Corporation
Ameren Corporation
American Electric Power Company, Inc.
Avista Corporation
Berkshire Hathaway Energy
Black Hills Corporation
Cleco Corporation
CMS Energy Corporation
Consolidated Edison, Inc.
DPL Inc.
DTE Energy Company
Duke Energy Corporation
Edison International
El Paso Electric Company
Empire District Electric Company
Entergy Corporation
Eversource Energy
Great Plains Energy Inc.
IDACORP, Inc.
IPALCO Enterprises, Inc.
NiSource Inc.
NorthWestern Corporation
OGE Energy Corp.
Otter Tail Corporation
PG&E Corporation
Pinnacle West Capital Corporation
PNM Resources, Inc.
Portland General Electric Company
PPL Corporation
Puget Energy, Inc.
Southern Company
TECO Energy, Inc.
Unitil Corporation
Vectren Corporation
WEC Energy Group, Inc.
Westar Energy, Inc.
Xcel Energy Inc.

Mostly Regulated (11 of 51)

ALLETE, Inc.
AVANGRID, Inc.
CenterPoint Energy, Inc.
Dominion Resources, Inc.
FirstEnergy Corp.
MDU Resources Group, Inc.
MGE Energy, Inc.
NextEra Energy, Inc.
Public Service Enterprise Group Incorporated
SCANA Corporation
Sempra Energy

Diversified (3 of 51)

Energy Future Holdings
Exelon Corporation
Hawaiian Electric Industries, Inc.

Note: Based on assets at 12/31/2015

Q1 2016

Rate Case Summary

HIGHLIGHTS

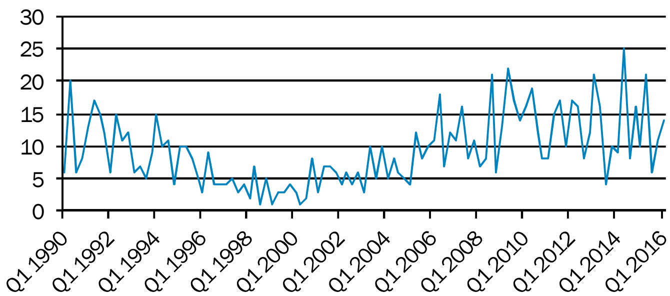
- Investor-owned electric utilities filed 14 new rate cases in Q1 2016. While the quarter's average awarded ROE is 10.26%, the figure was boosted by a Virginia Electric & Power case that included ROE incentives.
- The Q1 average requested ROE, at 10.39%, is near the low end of our three-decade dataset. Regulatory lag, at 9.45 months, is close to its historical ten month average.
- The primary reason for rate case filings is capital expenditures and this was true in Q1. The second major driver of Q1 filings was utilities' desire to implement rate mechanisms that allow for cost recovery between rate cases. A third was companies' desire to enhance ROEs. While ROE determination always plays a big part in rate cases, ROE enhancement efforts had a somewhat higher profile than usual during Q1 2016.

COMMENTARY

Investor-owned electric utilities filed 14 new rate cases in Q1 2016. The quarter's activity was consistent with the elevated pace of case filings in recent years compared to the pace at the turn of the century, when new filings averaged fewer than five per quarter. While the average awarded ROE in Q1 was 10.26%, the figure is deceptively high. The Virginia commission decided four Virginia Electric & Power cases that included ROE incentives for certain types of generation. In 2013, Virginia legislation limited the ROE adders to new construction of nuclear and off-shore wind facilities. However, the commission grandfathered previously approved incentives and four of five cases approved in Q1 for Virginia Electric Power reflected these. Nevertheless, 10.26% is at the low end of our three decades of data that show steadily declining ROEs. The quarter's average requested ROE, at 10.39%, is also near the low end of our historical data. A three-decade-long trend of declining interest rates accounts for much of the long-term decline in requested and awarded ROEs. Regulatory lag in Q1, at 9.45 months, is close to the historical average of about ten months.

I. Number of Rate Cases Filed (Quarterly)

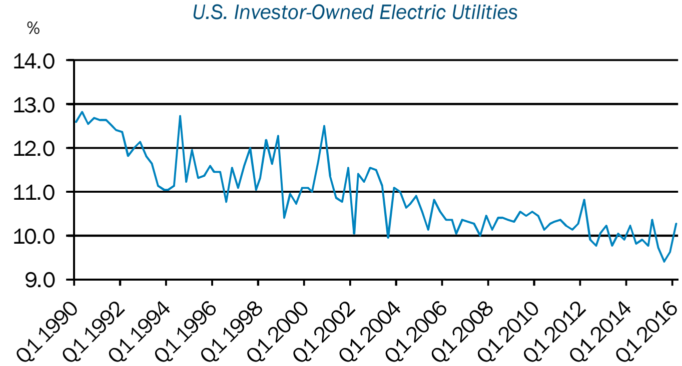
U.S. Investor-Owned Electric Utilities



Source: SNL Financial / Regulatory Research Assoc. and EEI Rate Department

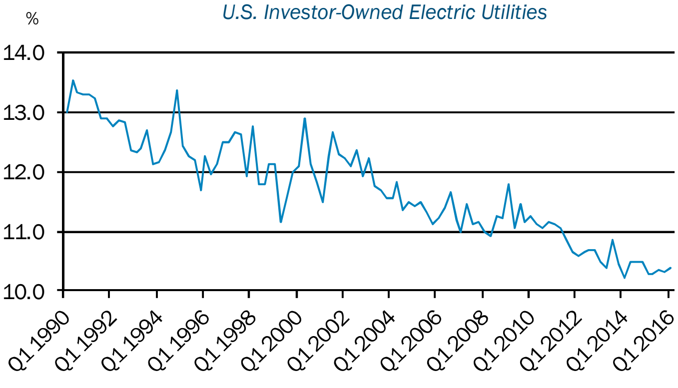
II. Average Awarded ROE (Quarterly)

U.S. Investor-Owned Electric Utilities



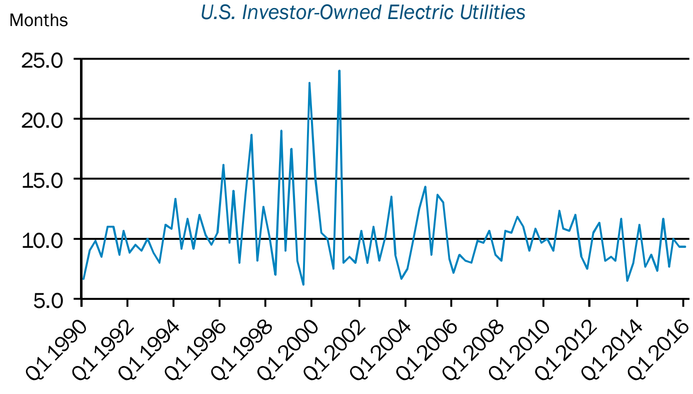
Source: SNL Financial / Regulatory Research Assoc. and EEI Rate Department

III. Average Requested ROE (Quarterly)



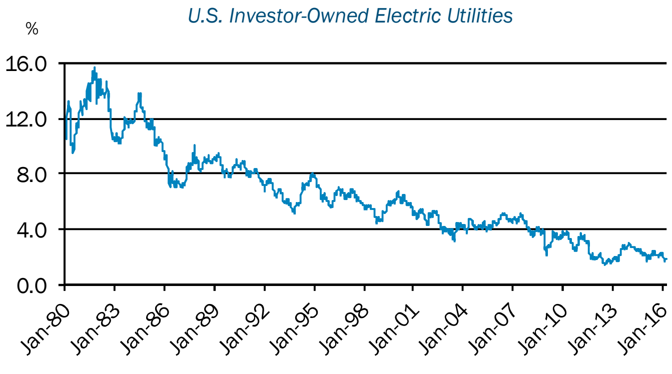
Source: SNL Financial / Regulatory Research Assoc. and EEI Rate Department

IV. Average Regulatory Lag (Quarterly)



Source: SNL Financial / Regulatory Research Assoc. and EEI Rate Department

V. 10-Year Treasury Yield (1/1980 — 3/2016)



Source: U.S. Federal Reserve

Filed Cases in Q1

The primary reason for rate case filings is capital expenditures and this was true in Q1. The second major driver of filings in Q1 was utilities' desire to implement rate mechanisms that allow for cost recovery between rate cases. A third cause was companies' desire to enhance ROEs; while ROE determination always plays a big part in rate cases, ROE enhancement efforts had a somewhat higher profile than usual.

Capital Expenditures

Southwestern Public Service in Texas filed in part for rate recognition of the Texas portion of its more than $1 billion in capital investment since June 30, 2014, the end of the test period for the company's last rate case. Investments encompassed the replacement, improvement and expansion of the company's generation, distribution and transmission systems to improve reliability and meet North American Reliability Corporation and environmental requirements. Capital expenditures in 2015 were $590 million and the company hopes to recover planned expenditures that range from $450 million to $790 million each year between 2016 and 2020. Those totals do not include expenditures resulting from the Environmental Protection Agency's Regional Haze Rule or the Clean Power Plan.

Florida Power & Light filed to recover a $16 billion investment program planned through 2017 to improve reliability, reduce emissions, improve generation fuel efficiency, strengthen the electric system against severe weather, accommodate customer growth and improve customer service.

Atlantic City Electric in New Jersey filed in part because it similarly believes present rates do not provide sufficient revenue to reflect increased investment in rate base. The company has invested $716 million since 2011 to improve its distribution system and expects to continue this level of investment over the next several years. Further, the company is seeking approval of its "Power Ahead" program, which it describes as "a comprehensive plan to advance the modernization of the electric grid through energy efficiency, increased distributed generation, and resiliency, all geared toward improving the distribution system's ability to withstand major storm events." This effort responds to a 2015 commission order encouraging utilities to find ways to harden New Jersey's infrastructure against damage from major storms. The company expects to spend $176 million for the program over the next five years.

Rate Mechanisms

In Michigan, DTE energy filed in part for a decoupling mechanism in the hope that legislation is enacted allowing such mechanisms. Kansas City Power & Light's (KCP&L's) Missouri Public Service and Saint Joseph Light & Power subsidiaries each filed in Missouri in part to recover variations in transmission-related costs in their fuel adjustment clauses, even though the Missouri commission recently rejected such requests by other utilities in the state. If the commission similarly rejects KCP&L's requests, the company hopes to include in rate base a forecasted annual average of transmission-related costs for 2017-2018.

Consumers Energy in Michigan filed in part for a recovery mechanism for capital investments beyond the test year, including $38.1 million in 2017 and $92 million in both 2018 and 2019, all subject to reconciliation. The company would also like to implement a revenue decoupling mechanism.

VI. Rate Case Data: From Tables I-V

U.S. Investor-Owned Electric Utilities

Quarter	Number of Rate Cases Filed	Average Awarded ROE	Average Requested ROE	Average 10-Year Treasury Yield	Average Regulatory Lag
Q4 1988	1	NA	14.30	8.96	NA
Q1 1989	4	NA	15.26	9.21	NA
Q2 1989	4	NA	13.30	8.77	NA
Q3 1989	14	NA	13.65	8.11	NA
Q4 1989	13	NA	13.47	7.91	NA
Q1 1990	6	12.62	13.00	8.42	6.71
Q2 1990	20	12.85	13.51	8.68	9.07
Q3 1990	6	12.54	13.34	8.70	9.90
Q4 1990	8	12.68	13.31	8.40	8.61
Q1 1991	13	12.66	13.29	8.02	11.00
Q2 1991	17	12.67	13.23	8.13	11.00
Q3 1991	15	12.49	12.89	7.94	8.70
Q4 1991	12	12.42	12.90	7.35	10.70
Q1 1992	6	12.38	12.77	7.30	8.90
Q2 1992	15	11.83	12.86	7.38	9.61
Q3 1992	11	12.03	12.81	6.62	9.00
Q4 1992	12	12.14	12.36	6.74	10.10
Q1 1993	6	11.84	12.33	6.28	8.87
Q2 1993	7	11.64	12.39	5.99	8.10
Q3 1993	5	11.15	12.70	5.62	11.20
Q4 1993	9	11.04	12.12	5.61	10.90
Q1 1994	15	11.07	12.15	6.07	13.40
Q2 1994	10	11.13	12.37	7.08	9.28
Q3 1994	11	12.75	12.66	7.33	11.80
Q4 1994	4	11.24	13.36	7.84	9.26
Q1 1995	10	11.96	12.44	7.48	12.00
Q2 1995	10	11.32	12.26	6.62	10.40
Q3 1995	8	11.37	12.19	6.32	9.50
Q4 1995	5	11.58	11.69	5.89	10.60
Q1 1996	3	11.46	12.25	5.91	16.30
Q2 1996	9	11.46	11.96	6.72	9.80
Q3 1996	4	10.76	12.13	6.78	14.00
Q4 1996	4	11.56	12.48	6.34	8.12
Q1 1997	4	11.08	12.50	6.56	13.80
Q2 1997	5	11.62	12.66	6.70	18.70
Q3 1997	3	12.00	12.63	6.24	8.33
Q4 1997	4	11.06	11.93	5.91	12.70
Q1 1998	2	11.31	12.75	5.59	10.20
Q2 1998	7	12.20	11.78	5.60	7.00
Q3 1998	1	11.65	NA	5.20	19.00
Q4 1998	5	12.30	12.11	4.67	9.11
Q1 1999	1	10.40	NA	4.98	17.60
Q2 1999	3	10.94	11.17	5.54	8.33
Q3 1999	3	10.75	11.57	5.88	6.33
Q4 1999	4	11.10	12.00	6.14	23.00
Q1 2000	3	11.08	12.10	6.48	15.10
Q2 2000	1	11.00	12.90	6.18	10.50
Q3 2000	2	11.68	12.13	5.89	10.00
Q4 2000	8	12.50	11.81	5.57	7.50
Q1 2001	3	11.38	11.50	5.05	24.00
Q2 2001	7	10.88	12.24	5.27	8.00
Q3 2001	7	10.78	12.64	4.98	8.62
Q4 2001	6	11.57	12.29	4.77	8.00
Q1 2002	4	10.05	12.22	5.08	10.80
Q2 2002	6	11.41	12.08	5.10	8.16
Q3 2002	4	11.25	12.36	4.26	11.00
Q4 2002	6	11.57	11.92	4.01	8.25

VI. Rate Case Data: From Tables I-V (cont.)

U.S. Investor-Owned Electric Utilities

Quarter	Number of Rate Cases Filed	Average Awarded ROE	Average Requested ROE	Average 10-Year Treasury Yield	Average Regulatory Lag
Q1 2003	3	11.49	12.24	3.92	10.20
Q2 2003	10	11.16	11.76	3.62	13.60
Q3 2003	5	9.95	11.69	4.23	8.80
Q4 2003	10	11.09	11.57	4.29	6.83
Q1 2004	5	11.00	11.54	4.02	7.66
Q2 2004	8	10.64	11.81	4.60	10.00
Q3 2004	6	10.75	11.35	4.30	12.50
Q4 2004	5	10.91	11.48	4.17	14.40
Q1 2005	4	10.55	11.41	4.30	8.71
Q2 2005	12	10.13	11.49	4.16	13.70
Q3 2005	8	10.84	11.32	4.21	13.00
Q4 2005	10	10.57	11.14	4.49	8.44
Q1 2006	11	10.38	11.23	4.57	7.33
Q2 2006	18	10.39	11.38	5.07	8.83
Q3 2006	7	10.06	11.64	4.90	8.33
Q4 2006	12	10.38	11.19	4.63	8.11
Q1 2007	11	10.30	11.00	4.68	9.88
Q2 2007	16	10.27	11.44	4.85	9.82
Q3 2007	8	10.02	11.13	4.73	10.80
Q4 2007	11	10.44	11.16	4.26	8.75
Q1 2008	7	10.15	10.98	3.66	7.33
Q2 2008	8	10.41	10.93	3.89	10.80
Q3 2008	21	10.42	11.26	3.86	10.60
Q4 2008	6	10.38	11.21	3.25	11.90
Q1 2009	13	10.31	11.79	2.74	11.10
Q2 2009	22	10.55	11.01	3.31	9.13
Q3 2009	17	10.46	11.43	3.52	10.90
Q4 2009	14	10.54	11.15	3.46	9.69
Q1 2010	16	10.45	11.24	3.72	10.00
Q2 2010	19	10.12	11.12	3.49	9.00
Q3 2010	12	10.27	11.07	2.79	12.40
Q4 2010	8	10.30	11.17	2.86	10.90
Q1 2011	8	10.35	11.11	3.46	10.80
Q2 2011	15	10.24	11.06	3.21	12.00
Q3 2011	17	10.13	10.86	2.43	8.64
Q4 2011	10	10.29	10.66	2.05	7.60
Q1 2012	17	10.84	10.57	2.04	10.50
Q2 2012	16	9.92	10.66	1.82	11.40
Q3 2012	8	9.78	10.68	1.64	8.20
Q4 2012	12	10.05	10.69	1.71	8.65
Q1 2013	21	10.23	10.48	1.95	8.24
Q2 2013	16	9.77	10.40	2.00	11.80
Q3 2013	4	10.06	10.85	2.71	6.55
Q4 2013	10	9.90	10.46	2.75	8.14
Q1 2014	9	10.23	10.22	2.76	11.30
Q2 2014	25	9.83	10.48	2.62	7.83
Q3 2014	8	9.89	10.48	2.50	8.67
Q4 2014	16	9.78	10.47	2.28	7.42
Q1 2015	10	10.37	10.29	2.17	11.80
Q2 2015	21	9.73	10.30	2.17	7.74
Q3 2015	6	9.40	10.35	2.22	10.00
Q4 2015	11	9.62	10.33	2.19	9.44
Q1 2016	14	10.26	10.39	1.92	9.45

NA = Not available
Source: SNL Financial / Regulatory Research Assoc. and EEI Rate Department

Residential Customer Charge

Avista filed in Washington in part to increase its residential customer charge from $8.50 to $9.50. KCP&L subsidiaries filed to increase their residential customer charges to $14.50 from $10.43 for Missouri Public Service and from $9.54 for Saint Joseph Light & Power. Atlantic City Electric filed in New Jersey in part to try to raise its residential customer charge from $4 to $6.

Decided Cases in Q1

Residential Customer Charge

In a case previous to the one filed in Q1, Avista filed in Washington in part to raise the residential customer charge from $8.50 to $14. A settlement of the case in Q1 left the residential customer charge at $8.50. Similarly, Kentucky Utilities wanted to raise the residential customer charge from $12 to $15 and then to $18 as of January 1, 2017, but a settlement left it at $12.

Rate Mechanisms

The Indiana commission had approved a rider for Northern Indiana Public Service to recover certain infrastructure investments. However, intervenors in the case appealed it to the Indiana Court of Appeals. The court remanded the rider back to the commission, saying the plan for the recovery associated with the rider lacked the specificity needed to determine reasonableness. The company made a separate filing that the commission approved and then dismissed the original filing, all following separate procedural efforts before the commission that provided additional information the commission found useful.

Also in Q1, the Indiana commission approved Indianapolis Power & Light's requested rider to recover non-fuel-related costs that vary from base-level costs associated with the company's participation in the regional transmission organization. The company must true up the rider annually. The company also requested similar treatment for net capacity costs, which the commission also approved, finding that if the company alters its generation mix the capacity rider will help smooth cost volatility. The commission also approved an off-system sales rider that shares shortages or overages equally between customers and shareholders, and a company-requested storm tracker rate mechanism. Alternatively in Montana, a settlement required MDU Resources to withdraw its requested transmission and environmental cost recovery riders.

Virginia ROE Incentives

Virginia state law requires biennial energy reviews for major investor-owned utilities. As part of these reviews, state law allows ROE incentives for certain types of generation. 2013 legislation limited these ROE adders to new construction of nuclear and off-shore wind facilities only. However, the 2013 law grandfathered incentive provisions approved previously. In Q1, four of five cases decided for Virginia Electric & Power (VE&P) reflected these incentives. In one case, VE&P's conversion of a plant from coal to biomass qualified for a 200-basis-point premium, resulting in an 11.6% approved ROE. Three other plants (a hybrid plant and two combined-cycle plants) each qualified for 100-basis-point premiums, resulting in 10.6% ROEs.

Indianapolis Power & Light

In the course of Indianapolis Power & Light's rate case, the company experienced underground explosions that resulted in power outages. In deciding the case in Q1, the commission said that it could support a 10% ROE, but lowered it to 9.85% to relay the commission's concern about the explosions and outages. The commission also instituted a collaborative process to address the company's asset management program, certain operating performance measures, and the company's commitment to infrastructure improvements. The commission also suggested that "additional written processes may be appropriate."

The commission determined that the company's prepaid pension asset "represents a component of working capital" and consequently should be in rate base. However, the commission said that laws mandating a minimum funding of the pension asset prevent those funds from being available for other uses by shareholders. Consequently, the commission would not award the company a return on the minimum pension funding. However, the commission found the additional discretionary prepaid pension asset was prudently incurred and therefore is eligible for inclusion in rate base.■

Docket No. 160021-EI

AARP Exhibit MLB-1.5

(22 pages)

AUS MONTHLY UTILITY REPORTS

JUNE 2016

ELECTRIC COMPANIES
NATURAL GAS COMPANIES
WATER COMPANIES

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MOUNT LAUREL, NJ 08054
(800) 637-4202
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- Index -

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1

2

ELECTRIC COMPANIES

		DIVIDEND YIELD	PRICE EARNINGS MULTIPLE
YEAR	2006	3.8	20.8
YEAR	2007	3.4	18.5
YEAR	2008	3.9	16.1
YEAR	2009	4.8	14.1
YEAR	2010	4.3	18.1
YEAR	2011	4.2	18.1
YEAR	2012	4.0	17.8
YEAR	2013	3.8	17.5
YEAR	2014	3.7	18.9
YEAR	2015	3.7	18.6
YEAR TO DATE	2016	3.6	19.3
JULY	2015	3.9	17.9
AUGUST	2015	3.7	18.5
SEPTEMBER	2015	3.6	19.0
OCTOBER	2015	3.8	17.7
NOVEMBER	2015	3.6	18.3
DECEMBER	2015	3.8	17.9
JANUARY	2016	3.8	18.1
FEBRUARY	2016	3.8	18.0
MARCH	2016	3.6	18.8
APRIL	2016	3.4	20.2
MAY	2016	3.5	20.1
JUNE	2016	3.5	20.3

COMBINED ELECTRIC & GAS DISTRIBUTION COMPANIES

		DIVIDEND YIELD	PRICE EARNINGS MULTIPLE
YEAR	2006	3.2	18.7
YEAR	2007	3.3	18.3
YEAR	2008	4.0	15.7
YEAR	2009	5.2	12.8
YEAR	2010	4.5	16.2
YEAR	2011	4.4	17.9
YEAR	2012	4.2	18.2
YEAR	2013	4.0	19.1
YEAR	2014	3.7	19.3
YEAR	2015	3.6	19.1
YEAR TO DATE	2016	3.5	21.1
JULY	2015	3.9	18.4
AUGUST	2015	3.7	18.5
SEPTEMBER	2015	3.6	18.2
OCTOBER	2015	3.9	17.0
NOVEMBER	2015	3.6	19.1
DECEMBER	2015	3.8	19.7
JANUARY	2016	3.7	19.9
FEBRUARY	2016	3.8	19.9
MARCH	2016	3.6	21.3
APRIL	2016	3.4	21.7
MAY	2016	3.4	21.4
JUNE	2016	3.4	22.2

NATURAL GAS DISTRIBUTION TRANSM. & INTEGRATED COMPANIES

		DIVIDEND YIELD	PRICE EARNINGS MULTIPLE
YEAR	2006	3.1	17.2
YEAR	2007	2.9	19.5
YEAR	2008	13.1	17.4
YEAR	2009	3.8	14.4
YEAR	2010	3.2	18.6
YEAR	2011	3.0	20.2
YEAR	2012	3.3	28.8
YEAR	2013	3.3	20.5
YEAR	2014	3.2	21.1
YEAR	2015	3.4	20.2
YEAR TO DATE	2016	3.3	22.5
JULY	2015	3.7	19.6
AUGUST	2015	3.6	20.0
SEPTEMBER	2015	3.6	20.1
OCTOBER	2015	3.7	19.5
NOVEMBER	2015	3.4	21.0
DECEMBER	2015	3.6	21.0
JANUARY	2016	3.7	20.1
FEBRUARY	2016	3.6	20.5
MARCH	2016	3.4	23.0
APRIL	2016	3.3	23.1
MAY	2016	2.9	23.7
JUNE	2016	3.1	24.4

WATER COMPANIES

		DIVIDEND YIELD	PRICE EARNINGS MULTIPLE
YEAR	2006	2.8	30.9
YEAR	2007	2.8	28.1
YEAR	2008	3.1	23.1
YEAR	2009	3.5	21.3
YEAR	2010	3.4	23.7
YEAR	2011	3.3	21.7
YEAR	2012	3.3	21.2
YEAR	2013	3.0	21.0
YEAR	2014	3.0	22.2
YEAR	2015	2.8	20.7
YEAR TO DATE	2016	2.5	24.3
JULY	2015	3.0	18.7
AUGUST	2015	2.8	19.7
SEPTEMBER	2015	2.9	19.6
OCTOBER	2015	2.9	20.0
NOVEMBER	2015	2.6	21.2
DECEMBER	2015	2.8	21.6
JANUARY	2016	2.7	22.3
FEBRUARY	2016	2.7	22.4
MARCH	2016	2.5	24.7
APRIL	2016	2.5	24.8
MAY	2016	2.4	26.0
JUNE	2016	2.4	25.6

ELECTRIC COMPANIES

COMPANY	LATEST 12 MONTHS EARNINGS AVAILABLE	PER SHARE: EARNINGS	PER SHARE: CURRENT ANNUAL DIVIDEND	DATA ($): BOOK VALUE (1)	STOCK PRICE 05/20/16	COMMON SHARES O/S MILL	PERCENT (2): DIV PAYOUT	PERCENT (2): DIV YIELD	PERCENT (2): MKT/ BOOK	DIV/ BOOK (2)	PRICE EARN MULT
ALLETE, Inc. (NYSE-ALE)	3/16	2.99	2.08	37.52	55.10	49.3	70	3.8	146.9	5.5	18.4
American Electric Power Co. (NYSE-AEP)	3/16	3.91	2.24	36.90	63.80	491.2	57	3.5	172.9	6.1	16.3
Edison International (NYSE-EIX)	3/16	3.01	1.92	35.11	70.05	325.8	64	2.7	199.5	5.5	23.3
El Paso Electric Company (NYSE-EE)	3/16	1.80	1.16	24.79	42.96	40.3	64	2.7	173.3	4.7	23.9
FirstEnergy Corporation (ASE-FE)	3/16	1.61	1.44	29.35	32.29	424.7	89	4.5	110.0	4.9	20.1
Great Plains Energy Incorporated (NYSE-GXP)	3/16	1.42	1.04	23.60	30.96	154.7	73	3.4	131.2	4.4	21.8
Hawaiian Electric Industries, Inc. (NYSE-HE)	3/16	1.49	1.24	18.00	32.30	107.9	83	3.8	179.4	6.9	21.7
IDACORP, Inc. (NYSE-IDA)	3/16	3.91	2.04	40.81	70.93	50.4	52	2.9	173.8	5.0	18.1
Nextera Energy (NYSE-NEE)	3/16	5.98	3.48	49.70	119.33	461.0	58	2.9	240.1	7.0	20.0
OGE Energy Corp. (NYSE-OGE)	3/16	1.27	1.12	16.52	30.56	199.7	88	3.7	185.0	6.8	24.1
Otter Tail Corporation (NDQ-OTTR)	3/16	1.48	1.24	16.12	29.04	38.1	84	4.3	180.1	7.7	19.6
Pinnacle West Capital Corp. (NYSE-PNW)	3/16	3.81	2.48	41.39	71.56	111.1	65	3.5	172.9	6.0	18.8
PNM Resources, Inc. (NYSE-PNM)	3/16	0.15	0.88	20.59	31.90	79.7	NM	2.8	154.9	4.3	NM
Portland General Electric Company (NYSE-POR)	3/16	2.09	1.28	25.77	40.44	88.9	61	3.2	156.9	5.0	19.3
PPL Corporation (NYSE-PPL)	3/16	2.26	1.52	14.43	37.96	676.4	67	4.0	263.1	10.5	16.8
Southern Company (NYSE-SO)	3/16	2.56	2.24	23.30	48.65	918.6	88	4.6	208.8	9.6	19.0
Westar Energy, Inc. (NYSE-WR)	3/16	2.16	1.52	25.92	52.39	141.6	70	2.9	202.1	5.9	24.3
AVERAGE							71	3.5	179.5	6.2	20.3

ELECTRIC COMPANIES

COMPANY	TOTAL REV $ MILL (1)	% REG ELEC REV	NET PLANT $ MILL	NET PLANT PER $ REV (1)	S&P BOND RATING	MOODY'S BOND RATING	COMMON EQUITY RATIO (3)	% RETURN ON BOOK VALUE		REGULATION	
								COMMON EQUITY (4)	TOTAL CAPITAL	ALLOWED ROE	ORDER DATE
ALLETE, Inc. (NYSE-ALE)	1,500.2	65	3,642.3	2.43	A-	A3	54.1	8.1	6.5	10.64	1/1/2013
American Electric Power Co. (NYSE-AEP)	16,032.9	81	46,832.9	2.92	BBB/BBB-	Baa1	46.3	10.9	6.6	10.12	10/3/2013
Edison International (NYSE-EIX)	11,452.0	100	35,323.0	3.08	BBB+	A2/A3	44.8	8.8	6.3	10.82	5/9/2013
El Paso Electric Company (NYSE-EE)	843.9	100	2,726.5	3.23	BBB	Baa1	42.3	7.4	6.0	11.25	12/8/2001
FirstEnergy Corporation (ASE-FE)	14,998.0	71	37,644.0	2.51	BBB	Baa2	35.8	5.5	5.2	10.45	3/2/2010
Great Plains Energy Incorporated (NYSE-GXP)	2,525.2	100	8,694.6	3.44	BBB	Baa2	47.2	6.1	5.5	9.50	7/1/2014
Hawaiian Electric Industries, Inc. (NYSE-HE)	2,516.1	89	4,423.6	1.76	BBB-	Baa2	48.8	8.4	6.2	9.67	5/31/2013
IDACORP, Inc. (NYSE-IDA)	1,271.8	100	4,009.7	3.15	A-	A3	52.4	9.8	7.4	NM	3/1/2012
Nextera Energy (NYSE-NEE)	17,216.0	66	62,894.0	3.65	A-/BBB+	A2/A3	40.9	12.7	7.8	10.50	1/1/2013
OGE Energy Corp. (NYSE-OGE)	2,149.9	100	7,387.5	3.44	BBB+	A3	53.9	7.7	6.6	9.98	6/17/2011
Otter Tail Corporation (NDQ-OTTR)	783.2	52	1,402.1	1.79	BBB-	Baa2	51.0	9.3	7.8	10.75	4/25/2011
Pinnacle West Capital Corp. (NYSE-PNW)	3,501.4	100	11,907.9	3.40	BBB	A3/Baa1	52.1	9.5	7.3	10.00	5/15/2012
PNM Resources, Inc. (NYSE-PNM)	1,417.2	100	4,746.7	3.35	BBB	Baa2	37.7	0.7	3.1	10.21	8/8/2011
Portland General Electric Company (NYSE-POR)	1,912.0	100	6,160.0	3.22	A-	A3	51.0	8.7	6.6	9.60	1/1/2016
PPL Corporation (NYSE-PPL)	7,450.0	60	29,832.0	4.00	A-	Baa1/Baa2	33.0	4.3	7.4	10.35	12/5/2012
Southern Company (NYSE-SO)	17,271.0	94	62,552.0	3.62	A	A3/Baa1	42.6	11.1	6.9	11.46	2/13/2013
Westar Energy, Inc. (NYSE-WR)	2,437.8	100	8,675.9	3.56	A-	A3/Baa1	50.2	8.8	6.7	10.15	3/1/2016
AVERAGE							46.1	8.1	6.5	10.34	

COMBINATION ELECTRIC & GAS COMPANIES

COMPANY	LATEST 12 MONTHS EARNINGS AVAILABLE	PER SHARE DATA ($) EARNINGS	CURRENT ANNUAL DIVIDEND	BOOK VALUE (1)	STOCK PRICE 05/20/16	COMMON SHARES O/S MILL	PERCENT (2) DIV PAYOUT	DIV YIELD	MKT/ BOOK	DIV/ BOOK (2)	PRICE EARN MULT
Alliant Energy Corporation (NYSE-LNT)	3/16	3.34	1.16	34.91	35.91	113.6	35	3.2	102.9	3.3	10.8
Ameren Corporation (NYSE-AEE)	3/16	2.53	1.72	28.31	47.24	242.6	68	3.6	166.9	6.1	18.7
Avista Corporation (NYSE-AVA)	3/16	2.11	1.36	25.15	39.84	63.2	64	3.4	158.4	5.4	18.9
Black Hills Corporation (NYSE-BKH)	3/16	-0.70	1.68	28.78	58.62	51.4	NM	2.9	203.7	5.8	NM
CenterPoint Energy (NYSE-CNP)	3/16	-1.55	1.04	8.14	22.07	430.6	NM	4.7	271.1	12.8	NM
Chesapeake Utilities Corporation (NYSE-CPK)	3/16	2.63	1.24	24.45	57.63	15.3	47	2.2	235.7	5.1	21.9
CMS Energy Corporation (NYSE-CMS)	3/16	1.75	1.24	14.72	40.85	279.2	71	3.0	277.5	8.4	23.3
Consolidated Edison, Inc. (NYSE-ED)	3/16	3.83	2.68	44.87	72.16	294.0	70	3.7	160.8	6.0	18.8
Dominion Resources, Inc. (NYSE-D)	3/16	3.18	2.80	21.57	70.98	597.0	88	3.9	329.1	13.0	22.3
DTE Energy Company (NYSE-DTE)	3/16	3.89	2.92	49.53	88.69	179.4	75	3.3	179.1	5.9	22.8
Duke Energy Corporation (NYSE-DUK)	3/16	3.83	3.28	57.90	77.00	689.0	86	4.3	133.0	5.7	20.1
Empire District Electric Co. (NYSE-EDE)	3/16	1.27	1.04	18.41	33.50	43.9	82	3.1	182.0	5.6	26.4
Entergy Corporation (NYSE-ETR)	3/16	-1.38	3.40	52.38	74.30	178.7	NM	4.6	141.8	6.5	NM
Eversource Energy (NYSE-ES)	3/16	2.73	1.76	32.91	54.91	317.2	64	3.2	166.8	5.3	20.1
Exelon Corporation (NYSE-EXC)	3/16	1.75	1.28	29.21	34.27	887.0	73	3.7	117.3	4.4	19.6
MDU Resources Group, Inc. (NYSE-MDU)	3/16	-1.50	0.76	12.12	21.62	195.3	NM	3.5	178.4	6.3	NM
MGE Energy, Inc. (NYSE-MGEE)	3/16	2.03	1.16	20.11	50.36	34.7	57	2.3	250.4	5.8	24.8
NiSource Inc. (NYSE-NI)	3/16	0.63	0.68	12.05	23.82	321.4	108	2.9	197.7	5.6	37.8
NorthWestern Corporation (NYSE-NWE)	3/16	2.87	2.00	31.08	56.52	52.0	70	3.5	181.9	6.4	19.7
PG&E Corporation (NYSE-PCG)	3/16	1.94	1.84	33.52	57.63	495.6	95	3.2	171.9	5.5	29.7
Public Service Enterprise Group (NYSE-PEG)	3/16	3.08	1.64	26.37	44.97	505.0	53	3.6	170.5	6.2	14.6
SCANA Corporation (NYSE-SCG)	3/16	3.65	2.28	38.76	68.41	142.9	62	3.3	176.5	5.9	18.7
TECO Energy, Inc. (NYSE-TE)	3/16	0.80	0.92	10.97	27.49	235.5	115	3.3	250.6	8.4	34.4
Unitil Corporation (ASE-UTL)	3/16	1.69	1.40	20.64	39.00	14.0	83	3.6	189.0	6.8	23.1
Vectren Corporation (NYSE-VVC)	3/16	2.28	1.60	20.54	48.29	82.8	70	3.3	235.1	7.8	21.2
Wisconsin Energy Corporation (NYSE-WEC)	3/16	2.58	2.00	28.03	58.51	315.6	78	3.4	208.7	7.1	22.7
Xcel Energy Inc. (NYSE-XEL)	3/16	2.11	1.36	21.01	40.47	508.0	64	3.4	192.6	6.5	19.2
AVERAGE							73	3.4	193.7	6.6	22.2
COMBINED ELECTRIC/COMBINATION ELECTRIC & GAS AVERAGES							72	3.4	186.6	6.4	21.2

COMBINATION ELECTRIC & GAS COMPANIES

COMPANY	TOTAL REV $ MILL (1)	% REG ELEC REV	% REG GAS REV	NET PLANT $ MILL	NET PLANT PER $ REV (1)	S&P BOND RATING	MOODY'S BOND RATING	COMMON EQUITY RATIO (3)	%RETURN ON BOOK VALUE: COMMON EQUITY (4)	%RETURN ON BOOK VALUE: TOTAL CAPITAL	REGULATION: ALLOWED ROE	REGULATION: ORDER DATE
Alliant Energy Corporation (NYSE-LNT)	3,200.0	87	10	9,626.6	3.01	A-	A2/A3	48.3	9.7	7.2	10.31	6/6/2014
Ameren Corporation (NYSE-AEE)	5,976.0	86	19	19,000.0	3.18	BBB+/BBB	Baa1	47.0	9.3	6.6	9.42	12/1/2015
Avista Corporation (NYSE-AVA)	1,456.5	68	34	3,927.6	2.70	A-	Baa1	50.3	8.6	6.6	10.19	1/11/2016
Black Hills Corporation (NYSE-BKH)	1,312.6	53	41	4,321.9	3.29	BBB	A3/Baa1	30.5	NM	1.8	10.60	1/1/2015
CenterPoint Energy (NYSE-CNP)	6,937.0	41	37	11,718.0	1.69	A-/BBB+	A3/Baa1	29.3	NM	NM	9.96	4/18/2011
Chesapeake Utilities Corporation (NYSE-CPK)	435.5	17	54	881.2	2.02	NR	NR	53.1	11.7	8.1	10.46	11/1/2014
CMS Energy Corporation (NYSE-CMS)	6,146.0	69	27	14,907.0	2.43	BBB+/BBB	A3/Baa1	30.7	12.3	6.8	10.50	11/1/2015
Consolidated Edison, Inc. (NYSE-ED)	12,094.0	71	14	32,112.0	2.66	A-/BBB+	A3	48.2	8.7	6.8	9.70	4/20/2015
Dominion Resources, Inc. (NYSE-D)	11,195.0	64	1	42,623.0	3.81	A-	A3/Baa1	30.0	15.2	6.8	9.88	7/1/2015
DTE Energy Company (NYSE-DTE)	9,919.0	49	13	18,127.0	1.83	A-/BBB+	A2/A3	48.1	8.0	6.4	10.65	10/20/2011
Duke Energy Corporation (NYSE-DUK)	23,016.0	91	2	76,432.0	3.32	BBB+	A3	47.6	6.5	5.3	10.17	5/1/2013
Empire District Electric Co. (NYSE-EDE)	592.3	92	6	2,036.3	3.44	A-	Baa1	48.1	7.0	6.0	NM	8/19/2008
Entergy Corporation (NYSE-ETR)	11,203.0	82	1	28,982.0	2.59	BBB+/BBB	Baa2/Baa3	37.8	NM	1.8	10.32	9/13/2012
Eversource Energy (NYSE-ES)	7,497.0	89	11	20,096.7	2.68	A-	A3/Baa1	50.4	8.5	6.1	9.32	6/12/2010
Exelon Corporation (NYSE-EXC)	28,189.0	39	4	69,406.0	2.46	BBB+/BBB	Baa1	41.1	7.1	4.9	9.53	12/10/2014
MDU Resources Group, Inc. (NYSE-MDU)	4,234.4	7	20	4,334.7	1.02	BBB+	NR	52.8	NM	5.2	10.75	12/30/2013
MGE Energy, Inc. (NYSE-MGEE)	541.4	75	24	1,251.5	2.31	AA-	Aa2	64.1	10.3	8.4	10.30	7/26/2013
NiSource Inc. (NYSE-NI)	4,520.6	35	53	12,267.2	2.71	BBB-	Baa1/Baa2	35.6	3.8	4.6	10.61	2/28/2014
NorthWestern Corporation (NYSE-NWE)	1,200.8	79	21	4,069.1	3.39	NR	A3	45.2	8.8	6.6	10.00	12/1/2015
PG&E Corporation (NYSE-PCG)	16,908.0	81	18	48,044.0	2.84	BBB/BBB-	A3/Baa1	48.5	5.9	5.3	10.40	12/20/2012
Public Service Enterprise Group (NYSE-PEG)	9,896.0	44	20	27,274.0	2.76	A-/BBB+	A2	56.5	12.1	8.7	10.30	6/18/2010
SCANA Corporation (NYSE-SCG)	4,164.0	60	18	13,365.0	3.21	BBB+	Baa1/Baa2	44.5	9.6	7.1	10.49	10/15/2014
TECO Energy, Inc. (NYSE-TE)	2,710.0	73	26	7,553.0	2.79	BBB+/BBB	A3	38.7	7.3	6.8	11.00	5/5/2009
Unitil Corporation (ASE-UTL)	380.4	52	46	813.1	2.14	NR	NR	43.2	8.2	6.8	9.52	5/30/2014
Vectren Corporation (NYSE-VVC)	2,313.3	25	31	3,718.1	1.61	A/A-	A2	49.6	11.3	8.3	10.34	4/27/2011
Wisconsin Energy Corporation (NYSE-WEC)	6,733.0	64	25	19,259.0	2.86	A-/BBB+	A1/A2	46.9	11.8	8.1	9.93	1/21/2015
Xcel Energy Inc. (NYSE-XEL)	10,834.5	85	14	31,433.4	2.90	A-	A3	43.3	10.3	7.1	9.46	12/3/2015
AVERAGE								44.8	9.2	6.3	10.16	
COMBINED ELECTRIC/COMBINATION ELECTRIC & GAS AVERAGES								45	8.7	6.4	10.25	

NATURAL GAS DISTRIBUTION & INTEGRATED NAT. GAS COMPANIES

COMPANY	LATEST 12 MONTHS EARNINGS AVAILABLE	PER SHARE DATA ($)				COMMON SHARES O/S MILL	PERCENT (2)			DIV/ BOOK (2)	PRICE EARN MULT
		EARNINGS	CURRENT ANNUAL DIVIDEND	BOOK VALUE (1)	STOCK PRICE 05/20/16		DIV PAYOUT	DIV YIELD	MKT/ BOOK		
AGL Resources Inc. (NYSE-GAS)	3/16	2.84	2.12	33.41	65.63	120.7	75	3.2	196.4	6.3	23.1
Atmos Energy Corporation (NYSE-ATO)	3/16	3.16	1.68	32.72	72.10	102.2	53	2.3	220.4	5.1	22.8
Delta Natural Gas Company (NDQ-DGAS)	3/16	0.73	0.80	11.11	25.37	7.1	110	3.2	228.4	7.2	34.8
Gas Natural, Inc. (NDQ-EGAS)	3/16	0.24	0.32	9.35	6.88	10.5	133	4.7	73.6	3.4	28.7
National Fuel Gas Company (NYSE-NFG)	3/16	-9.66	1.60	19.11	53.96	84.9	NM	3.0	282.4	8.4	NM
New Jersey Resources Corp. (NYSE-NJR)	3/16	1.36	0.96	14.05	34.75	86.0	71	2.8	247.3	6.8	25.6
Northwest Natural Gas Co. (NYSE-NWN)	3/16	2.25	1.88	29.35	55.25	27.5	84	3.4	188.2	6.4	24.6
Piedmont Natural Gas Co., Inc. (NYSE-PNY)	1/16	1.76	1.36	18.61	59.86	81.1	77	2.3	321.7	7.3	34.0
Questar Corporation (NYSE-STR)	3/16	1.15	0.88	7.76	25.19	175.4	77	3.5	324.6	11.3	21.9
RGC Resources, Inc. (NDQ-RGCO)	3/16	1.13	0.80	11.87	23.00	4.8	71	3.5	193.8	6.7	20.4
South Jersey Industries, Inc. (NYSE-SJI)	3/16	1.73	1.04	15.35	28.19	71.2	60	3.7	183.6	6.8	16.3
Southwest Gas Corporation (NYSE-SWX)	3/16	2.97	1.80	34.81	68.04	47.5	61	2.6	195.5	5.2	22.9
UGI Corporation (NYSE-UGI)	3/16	1.98	0.96	16.91	43.12	173.8	48	2.2	255.0	5.7	21.8
WGL Holdings, Inc. (NYSE-WGL)	3/16	3.18	1.96	2.99	64.50	466.5	62	3.0	2,157.2	65.6	20.3
AVERAGE							75	3.1	362.0	10.9	24.4

NATURAL GAS DISTRIBUTION & INTEGRATED NAT. GAS COMPANIES

COMPANY	TOTAL REV $ MILL (1)	% REG GAS REV	NET PLANT $ MILL	NET PLANT PER $ REV (1)	S&P BOND RATING	MOODY'S BOND RATING	COMMON EQUITY RATIO (3)	% RETURN ON BOOK VALUE		REGULATION	
								COMMON EQUITY (4)	TOTAL CAPITAL	ALLOWED ROE	ORDER DATE
AGL Resources Inc. (NYSE-GAS)	3,554.0	73	9,944.0	2.80	A-/BBB+	A2/A3	48.4	8.6	6.3	10.42	11/3/2010
Atmos Energy Corporation (NYSE-ATO)	3,381.8	71	7,839.4	2.32	A-	A2	52.0	10.0	7.2	9.81	9/9/2014
Delta Natural Gas Company (NDQ-DGAS)	65.2	63	137.8	2.11	NR	NR	60.2	6.7	5.9	10.40	10/1/2010
Gas Natural, Inc. (NDQ-EGAS)	96.9	91	140.7	1.45	NR	NR	63.0	2.5	1.8	12.63	NA
National Fuel Gas Company (NYSE-NFG)	1,465.2	49	4,572.2	3.12	BBB	Baa1	43.8	NM	NM	9.50	12/12/2007
New Jersey Resources Corp. (NYSE-NJR)	1,915.2	31	2,242.7	1.17	A+	Aa2	54.5	10.1	6.9	10.30	10/1/2008
Northwest Natural Gas Co. (NYSE-NWN)	717.7	97	2,196.7	3.06	AA-	A1	51.5	7.8	6.5	9.80	11/1/2012
Piedmont Natural Gas Co., Inc. (NYSE-PNY)	1,225.8	91	4,424.5	3.61	A	A2	42.3	9.8	6.5	10.40	1/23/2012
Questar Corporation (NYSE-STR)	1,162.6	98	3,860.5	3.32	A/A-	A2	48.4	15.2	10.0	9.68	3/1/2015
RGC Resources, Inc. (NDQ-RGCO)	58.3	99	124.4	2.13	NR	NR	63.8	9.7	7.9	9.75	5/9/2014
South Jersey Industries, Inc. (NYSE-SJI)	909.7	50	2,478.2	2.72	A	A2	43.6	11.6	6.4	9.75	10/1/2014
Southwest Gas Corporation (NYSE-SWX)	2,460.7	58	3,929.0	1.60	A-	A3	53.5	8.8	6.9	9.75	6/12/2014
UGI Corporation (NYSE-UGI)	5,809.6	12	5,083.1	0.87	NR	A2	37.7	12.1	7.7	11.60	8/11/2011
WGL Holdings, Inc. (NYSE-WGL)	2,357.9	45	3,832.5	1.63	A+	A1	53.3	11.9	8.3	9.58	11/22/2013
AVERAGE							51.1	9.6	6.8	10.24	

WATER COMPANIES

COMPANY	LATEST 12 MONTHS EARNINGS AVAILABLE	PER SHARE DATA ($) EARNINGS	CURRENT ANNUAL DIVIDEND	BOOK VALUE (1)	STOCK PRICE 05/20/16	COMMON SHARES O/S MILL	PERCENT (2) DIV PAYOUT	DIV YIELD	MKT/ BOOK	DIV/ BOOK (2)	PRICE EARN MULT
American States Water Co. (NYSE-AWR)	3/16	1.56	0.88	12.79	38.10	36.6	56	2.3	297.9	6.9	24.4
American Water Works Co., Inc. (NYSE-AWK)	3/16	2.65	1.52	28.01	73.41	181.4	57	2.1	262.1	5.4	27.7
Aqua America, Inc. (NYSE-WTR)	3/16	1.15	0.72	9.93	31.60	177.3	63	2.3	318.2	7.3	27.5
Artesian Resources Corp. (NDQ-ARTNA)	3/16	1.28	0.88	16.30	27.50	8.2	69	3.2	168.7	5.4	21.5
California Water Service Group (NYSE-CWT)	3/16	0.89	0.68	13.19	28.22	48.0	76	2.4	213.9	5.2	31.7
Connecticut Water Service, Inc. (NDQ-CTWS)	3/16	2.04	1.12	20.20	46.85	11.2	55	2.4	231.9	5.5	23.0
Middlesex Water Company (NDQ-MSEX)	3/16	1.28	0.80	12.86	35.79	16.2	63	2.2	278.3	6.2	28.0
SJW Corporation (NYSE-SJW)	3/16	1.77	0.80	18.81	32.76	20.4	45	2.4	174.2	4.3	18.5
York Water Company (NDQ-YORW)	3/16	0.96	0.64	8.59	27.27	12.8	67	2.3	317.5	7.5	28.4
AVERAGE							61	2.4	251.4	6.0	25.6

WATER COMPANIES

COMPANY	TOTAL REV $ MILL (1)	% REG WATER REV	NET PLANT $ MILL	NET PLANT PER $ REV (1)	S&P BOND RATING	MOODY'S BOND RATING	COMMON EQUITY RATIO (3)	%RETURN ON BOOK VALUE COMMON EQUITY (4)	TOTAL CAPITAL	REGULATION ALLOWED ROE	ORDER DATE
American States Water Co. (NYSE-AWR)	451.2	72	1,079.3	2.39	A+	A2	56.2	12.1	9.7	9.43	1/1/2013
American Water Works Co., Inc. (NYSE-AWK)	3,204.3	86	14,098.0	4.40	A+/A	A3/Baa1	42.9	9.5	6.9	9.75	12/12/2012
Aqua America, Inc. (NYSE-WTR)	816.5	96	4,752.9	5.82	AA-	NR	49.4	11.9	8.2	9.79	5/2/2014
Artesian Resources Corp. (NDQ-ARTNA)	77.5	94	407.2	5.25	NR	NR	54.4	9.0	7.6	10.00	5/2/2014
California Water Service Group (NYSE-CWT)	588.1	99	1,739.7	2.96	AA-	NR	51.4	6.8	5.9	9.43	1/1/2013
Connecticut Water Service, Inc. (NDQ-CTWS)	102.9	96	554.5	5.39	A/A-	NR	52.6	10.4	7.2	9.63	3/25/2014
Middlesex Water Company (NDQ-MSEX)	127.8	87	486.5	3.81	A	NR	59.6	10.3	7.5	9.75	8/19/2014
SJW Corporation (NYSE-SJW)	304.1	103	1,042.5	3.43	A	NR	47.8	9.8	7.5	9.43	1/1/2013
York Water Company (NDQ-YORW)	47.2	100	261.9	5.55	A-	NR	56.6	11.5	9.1	NM	2/28/2014
AVERAGE							52.3	10.2	7.7	9.65	

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AUS INDUSTRY RANKINGS

Dividend Yield
Market/Book Ratio
Price Earnings Multiple
Return on Book Value
of Common Equity

Industry rankings are based on the financial statistics reported in the preceding pages. These rankings are organized and presented for the reader's convenience. They do not represent a recommendation to buy or sell shares of common stock.

ELECTRIC COMPANIES

DIVIDEND YIELD

HIGH		LOW	
Southern Company (NYSE-SO)	4.6	El Paso Electric Company (NYSE-EE)	2.7
FirstEnergy Corporation (ASE-FE)	4.5	Edison International (NYSE-EIX)	2.7
Otter Tail Corporation (NDQ-OTTR)	4.3	PNM Resources, Inc. (NYSE-PNM)	2.8
PPL Corporation (NYSE-PPL)	4.0	IDACORP, Inc. (NYSE-IDA)	2.9
Hawaiian Electric Industries, Inc. (NYSE-HE)	3.8	Westar Energy, Inc. (NYSE-WR)	2.9
ALLETE, Inc. (NYSE-ALE)	3.8	Nextera Energy (NYSE-NEE)	2.9
OGE Energy Corp. (NYSE-OGE)	3.7	Portland General Electric Company (NYSE-POR)	3.2
American Electric Power Co. (NYSE-AEP)	3.5	Great Plains Energy Incorporated (NYSE-GXP)	3.4
Pinnacle West Capital Corp. (NYSE-PNW)	3.5	Pinnacle West Capital Corp. (NYSE-PNW)	3.5
Great Plains Energy Incorporated (NYSE-GXP)	3.4	American Electric Power Co. (NYSE-AEP)	3.5

MARKET/BOOK RATIO

HIGH		LOW	
PPL Corporation (NYSE-PPL)	263.1	FirstEnergy Corporation (ASE-FE)	110.0
Nextera Energy (NYSE-NEE)	240.1	Great Plains Energy Incorporated (NYSE-GXP)	131.2
Southern Company (NYSE-SO)	208.8	ALLETE, Inc. (NYSE-ALE)	146.9
Westar Energy, Inc. (NYSE-WR)	202.1	PNM Resources, Inc. (NYSE-PNM)	154.9
Edison International (NYSE-EIX)	199.5	Portland General Electric Company (NYSE-POR)	156.9
OGE Energy Corp. (NYSE-OGE)	185.0	American Electric Power Co. (NYSE-AEP)	172.9
Otter Tail Corporation (NDQ-OTTR)	180.1	Pinnacle West Capital Corp. (NYSE-PNW)	172.9
Hawaiian Electric Industries, Inc. (NYSE-HE)	179.4	El Paso Electric Company (NYSE-EE)	173.3
IDACORP, Inc. (NYSE-IDA)	173.8	IDACORP, Inc. (NYSE-IDA)	173.8
El Paso Electric Company (NYSE-EE)	173.3	Hawaiian Electric Industries, Inc. (NYSE-HE)	179.4

PRICE/EARNINGS MULTIPLE

HIGH		LOW	
Westar Energy, Inc. (NYSE-WR)	24.3	American Electric Power Co. (NYSE-AEP)	16.3
OGE Energy Corp. (NYSE-OGE)	24.1	PPL Corporation (NYSE-PPL)	16.8
El Paso Electric Company (NYSE-EE)	23.9	IDACORP, Inc. (NYSE-IDA)	18.1
Edison International (NYSE-EIX)	23.3	ALLETE, Inc. (NYSE-ALE)	18.4
Great Plains Energy Incorporated (NYSE-GXP)	21.8	Pinnacle West Capital Corp. (NYSE-PNW)	18.8
Hawaiian Electric Industries, Inc. (NYSE-HE)	21.7	Southern Company (NYSE-SO)	19.0
FirstEnergy Corporation (ASE-FE)	20.1	Portland General Electric Company (NYSE-POR)	19.3
Nextera Energy (NYSE-NEE)	20.0	Otter Tail Corporation (NDQ-OTTR)	19.6
Otter Tail Corporation (NDQ-OTTR)	19.6	Nextera Energy (NYSE-NEE)	20.0
Portland General Electric Company (NYSE-POR)	19.3	FirstEnergy Corporation (ASE-FE)	20.1

RETURN ON BOOK VALUE OF COMMON EQUITY

HIGH		LOW	
Nextera Energy (NYSE-NEE)	12.7	PNM Resources, Inc. (NYSE-PNM)	0.7
Southern Company (NYSE-SO)	11.1	PPL Corporation (NYSE-PPL)	4.3
American Electric Power Co. (NYSE-AEP)	10.9	FirstEnergy Corporation (ASE-FE)	5.5
IDACORP, Inc. (NYSE-IDA)	9.8	Great Plains Energy Incorporated (NYSE-GXP)	6.1
Pinnacle West Capital Corp. (NYSE-PNW)	9.5	El Paso Electric Company (NYSE-EE)	7.4
Otter Tail Corporation (NDQ-OTTR)	9.3	OGE Energy Corp. (NYSE-OGE)	7.7
Edison International (NYSE-EIX)	8.8	ALLETE, Inc. (NYSE-ALE)	8.1
Westar Energy, Inc. (NYSE-WR)	8.8	Hawaiian Electric Industries, Inc. (NYSE-HE)	8.4
Portland General Electric Company (NYSE-POR)	8.7	Portland General Electric Company (NYSE-POR)	8.7
Hawaiian Electric Industries, Inc. (NYSE-HE)	8.4	Westar Energy, Inc. (NYSE-WR)	8.8

COMBINATION ELECTRIC & GAS COMPANIES

DIVIDEND YIELD

HIGH		LOW	
CenterPoint Energy (NYSE-CNP)	4.7	Chesapeake Utilities Corporation (NYSE-CPK)	2.2
Entergy Corporation (NYSE-ETR)	4.6	MGE Energy, Inc. (NYSE-MGEE)	2.3
Duke Energy Corporation (NYSE-DUK)	4.3	NiSource Inc. (NYSE-NI)	2.9
Dominion Resources, Inc. (NYSE-D)	3.9	Black Hills Corporation (NYSE-BKH)	2.9
Exelon Corporation (NYSE-EXC)	3.7	CMS Energy Corporation (NYSE-CMS)	3.0
Consolidated Edison, Inc. (NYSE-ED)	3.7	Empire District Electric Co. (NYSE-EDE)	3.1
Public Service Enterprise Group (NYSE-PEG)	3.6	PG&E Corporation (NYSE-PCG)	3.2
Ameren Corporation (NYSE-AEE)	3.6	Eversource Energy (NYSE-ES)	3.2
Unitil Corporation (ASE-UTL)	3.6	Alliant Energy Corporation (NYSE-LNT)	3.2
NorthWestern Corporation (NYSE-NWE)	3.5	DTE Energy Company (NYSE-DTE)	3.3

MARKET/BOOK RATIO

HIGH		LOW	
Dominion Resources, Inc. (NYSE-D)	329.1	Alliant Energy Corporation (NYSE-LNT)	102.9
CMS Energy Corporation (NYSE-CMS)	277.5	Exelon Corporation (NYSE-EXC)	117.3
CenterPoint Energy (NYSE-CNP)	271.1	Duke Energy Corporation (NYSE-DUK)	133.0
TECO Energy, Inc. (NYSE-TE)	250.6	Entergy Corporation (NYSE-ETR)	141.8
MGE Energy, Inc. (NYSE-MGEE)	250.4	Avista Corporation (NYSE-AVA)	158.4
Chesapeake Utilities Corporation (NYSE-CPK)	235.7	Consolidated Edison, Inc. (NYSE-ED)	160.8
Vectren Corporation (NYSE-VVC)	235.1	Eversource Energy (NYSE-ES)	166.8
Wisconsin Energy Corporation (NYSE-WEC)	208.7	Ameren Corporation (NYSE-AEE)	166.9
Black Hills Corporation (NYSE-BKH)	203.7	Public Service Enterprise Group (NYSE-PEG)	170.5
NiSource Inc. (NYSE-NI)	197.7	PG&E Corporation (NYSE-PCG)	171.9

PRICE/EARNINGS MULTIPLE

HIGH		LOW	
NiSource Inc. (NYSE-NI)	37.8	Alliant Energy Corporation (NYSE-LNT)	10.8
TECO Energy, Inc. (NYSE-TE)	34.4	Public Service Enterprise Group (NYSE-PEG)	14.6
PG&E Corporation (NYSE-PCG)	29.7	Ameren Corporation (NYSE-AEE)	18.7
Empire District Electric Co. (NYSE-EDE)	26.4	SCANA Corporation (NYSE-SCG)	18.7
MGE Energy, Inc. (NYSE-MGEE)	24.8	Consolidated Edison, Inc. (NYSE-ED)	18.8
CMS Energy Corporation (NYSE-CMS)	23.3	Avista Corporation (NYSE-AVA)	18.9
Unitil Corporation (ASE-UTL)	23.1	Xcel Energy Inc. (NYSE-XEL)	19.2
DTE Energy Company (NYSE-DTE)	22.8	Exelon Corporation (NYSE-EXC)	19.6
Wisconsin Energy Corporation (NYSE-WEC)	22.7	NorthWestern Corporation (NYSE-NWE)	19.7
Dominion Resources, Inc. (NYSE-D)	22.3	Duke Energy Corporation (NYSE-DUK)	20.1

RETURN ON BOOK VALUE OF COMMON EQUITY

HIGH		LOW	
Dominion Resources, Inc. (NYSE-D)	15.2	NiSource Inc. (NYSE-NI)	3.8
CMS Energy Corporation (NYSE-CMS)	12.3	PG&E Corporation (NYSE-PCG)	5.9
Public Service Enterprise Group (NYSE-PEG)	12.1	Duke Energy Corporation (NYSE-DUK)	6.5
Wisconsin Energy Corporation (NYSE-WEC)	11.8	Empire District Electric Co. (NYSE-EDE)	7.0
Chesapeake Utilities Corporation (NYSE-CPK)	11.7	Exelon Corporation (NYSE-EXC)	7.1
Vectren Corporation (NYSE-VVC)	11.3	TECO Energy, Inc. (NYSE-TE)	7.3
Xcel Energy Inc. (NYSE-XEL)	10.3	DTE Energy Company (NYSE-DTE)	8.0
MGE Energy, Inc. (NYSE-MGEE)	10.3	Unitil Corporation (ASE-UTL)	8.2
Alliant Energy Corporation (NYSE-LNT)	9.7	Eversource Energy (NYSE-ES)	8.5
SCANA Corporation (NYSE-SCG)	9.6	Avista Corporation (NYSE-AVA)	8.6

NATURAL GAS DIST. & INT GAS COMPANIES

DIVIDEND YIELD

HIGH		LOW	
Gas Natural, Inc. (NDQ-EGAS)	4.7	UGI Corporation (NYSE-UGI)	2.2
South Jersey Industries, Inc. (NYSE-SJI)	3.7	Piedmont Natural Gas Co., Inc. (NYSE-PNY)	2.3
Questar Corporation (NYSE-STR)	3.5	Atmos Energy Corporation (NYSE-ATO)	2.3
RGC Resources, Inc. (NDQ-RGCO)	3.5	Southwest Gas Corporation (NYSE-SWX)	2.6
Northwest Natural Gas Co. (NYSE-NWN)	3.4	New Jersey Resources Corp. (NYSE-NJR)	2.8
AGL Resources Inc. (NYSE-GAS)	3.2	National Fuel Gas Company (NYSE-NFG)	3.0
Delta Natural Gas Company (NDQ-DGAS)	3.2	WGL Holdings, Inc. (NYSE-WGL)	3.0
WGL Holdings, Inc. (NYSE-WGL)	3.0	Delta Natural Gas Company (NDQ-DGAS)	3.2
National Fuel Gas Company (NYSE-NFG)	3.0	AGL Resources Inc. (NYSE-GAS)	3.2
New Jersey Resources Corp. (NYSE-NJR)	2.8	Northwest Natural Gas Co. (NYSE-NWN)	3.4

MARKET/BOOK RATIO

HIGH		LOW	
WGL Holdings, Inc. (NYSE-WGL)	2157.2	Gas Natural, Inc. (NDQ-EGAS)	73.6
Questar Corporation (NYSE-STR)	324.6	South Jersey Industries, Inc. (NYSE-SJI)	183.6
Piedmont Natural Gas Co., Inc. (NYSE-PNY)	321.7	Northwest Natural Gas Co. (NYSE-NWN)	188.2
National Fuel Gas Company (NYSE-NFG)	282.4	RGC Resources, Inc. (NDQ-RGCO)	193.8
UGI Corporation (NYSE-UGI)	255.0	Southwest Gas Corporation (NYSE-SWX)	195.5
New Jersey Resources Corp. (NYSE-NJR)	247.3	AGL Resources Inc. (NYSE-GAS)	196.4
Delta Natural Gas Company (NDQ-DGAS)	228.4	Atmos Energy Corporation (NYSE-ATO)	220.4
Atmos Energy Corporation (NYSE-ATO)	220.4	Delta Natural Gas Company (NDQ-DGAS)	228.4
AGL Resources Inc. (NYSE-GAS)	196.4	New Jersey Resources Corp. (NYSE-NJR)	247.3
Southwest Gas Corporation (NYSE-SWX)	195.5	UGI Corporation (NYSE-UGI)	255.0

PRICE/EARNINGS MULTIPLE

HIGH		LOW	
Delta Natural Gas Company (NDQ-DGAS)	34.8	South Jersey Industries, Inc. (NYSE-SJI)	16.3
Piedmont Natural Gas Co., Inc. (NYSE-PNY)	34.0	WGL Holdings, Inc. (NYSE-WGL)	20.3
Gas Natural, Inc. (NDQ-EGAS)	28.7	RGC Resources, Inc. (NDQ-RGCO)	20.4
New Jersey Resources Corp. (NYSE-NJR)	25.6	UGI Corporation (NYSE-UGI)	21.8
Northwest Natural Gas Co. (NYSE-NWN)	24.6	Questar Corporation (NYSE-STR)	21.9
AGL Resources Inc. (NYSE-GAS)	23.1	Atmos Energy Corporation (NYSE-ATO)	22.8
Southwest Gas Corporation (NYSE-SWX)	22.9	Southwest Gas Corporation (NYSE-SWX)	22.9
Atmos Energy Corporation (NYSE-ATO)	22.8	AGL Resources Inc. (NYSE-GAS)	23.1
Questar Corporation (NYSE-STR)	21.9	Northwest Natural Gas Co. (NYSE-NWN)	24.6
UGI Corporation (NYSE-UGI)	21.8	New Jersey Resources Corp. (NYSE-NJR)	25.6

RETURN ON BOOK VALUE OF COMMON EQUITY

HIGH		LOW	
Questar Corporation (NYSE-STR)	15.2	Gas Natural, Inc. (NDQ-EGAS)	2.5
UGI Corporation (NYSE-UGI)	12.1	Delta Natural Gas Company (NDQ-DGAS)	6.7
WGL Holdings, Inc. (NYSE-WGL)	11.9	Northwest Natural Gas Co. (NYSE-NWN)	7.8
South Jersey Industries, Inc. (NYSE-SJI)	11.6	AGL Resources Inc. (NYSE-GAS)	8.6
New Jersey Resources Corp. (NYSE-NJR)	10.1	Southwest Gas Corporation (NYSE-SWX)	8.8
Atmos Energy Corporation (NYSE-ATO)	10.0	RGC Resources, Inc. (NDQ-RGCO)	9.7
Piedmont Natural Gas Co., Inc. (NYSE-PNY)	9.8	Piedmont Natural Gas Co., Inc. (NYSE-PNY)	9.8
RGC Resources, Inc. (NDQ-RGCO)	9.7	Atmos Energy Corporation (NYSE-ATO)	10.0
Southwest Gas Corporation (NYSE-SWX)	8.8	New Jersey Resources Corp. (NYSE-NJR)	10.1
AGL Resources Inc. (NYSE-GAS)	8.6	South Jersey Industries, Inc. (NYSE-SJI)	11.6

WATER COMPANIES

DIVIDEND YIELD

HIGH		LOW	
Artesian Resources Corp. (NDQ-ARTNA)	3.2	American Water Works Co., Inc. (NYSE-AWK)	2.1
SJW Corporation (NYSE-SJW)	2.4	Middlesex Water Company (NDQ-MSEX)	2.2
California Water Service Group (NYSE-CWT)	2.4	Aqua America, Inc. (NYSE-WTR)	2.3
Connecticut Water Service, Inc. (NDQ-CTWS)	2.4	American States Water Co. (NYSE-AWR)	2.3

MARKET/BOOK RATIO

HIGH		LOW	
Aqua America, Inc. (NYSE-WTR)	318.2	Artesian Resources Corp. (NDQ-ARTNA)	168.7
York Water Company (NDQ-YORW)	317.5	SJW Corporation (NYSE-SJW)	174.2
American States Water Co. (NYSE-AWR)	297.9	California Water Service Group (NYSE-CWT)	213.9
Middlesex Water Company (NDQ-MSEX)	278.3	Connecticut Water Service, Inc. (NDQ-CTWS)	231.9

PRICE/EARNINGS MULTIPLE

HIGH		LOW	
California Water Service Group (NYSE-CWT)	31.7	SJW Corporation (NYSE-SJW)	18.5
York Water Company (NDQ-YORW)	28.4	Artesian Resources Corp. (NDQ-ARTNA)	21.5
Middlesex Water Company (NDQ-MSEX)	28.0	Connecticut Water Service, Inc. (NDQ-CTWS)	23.0
American Water Works Co., Inc. (NYSE-AWK)	27.7	American States Water Co. (NYSE-AWR)	24.4

RETURN ON BOOK VALUE OF COMMON EQUITY

HIGH		LOW	
American States Water Co. (NYSE-AWR)	12.1	California Water Service Group (NYSE-CWT)	6.8
Aqua America, Inc. (NYSE-WTR)	11.9	Artesian Resources Corp. (NDQ-ARTNA)	9.0
York Water Company (NDQ-YORW)	11.5	American Water Works Co., Inc. (NYSE-AWK)	9.5
Connecticut Water Service, Inc. (NDQ-CTWS)	10.4	SJW Corporation (NYSE-SJW)	9.8

GLOSSARY OF TERMS

Latest 12 Month Earnings Available -
Earnings per share as reported, based upon the latest 12 months ending as of the last day of the month reported in this column.

Earnings -
Earnings per share as reported before extraordinary items for the latest 12 months ending on the date reported.

Current Annual Dividend -
Latest quarterly dividend per share annualized.

Book Value -
Common equity divided by Common Shares Outstanding for the latest end figures available.

Price -
Closing market price per share of common stock on the date cited at the head of the column.

Common Shares Outstanding -
Common shares Outstanding for the latest quarter end figures available.

Dividend Payout -
Annualized Dividend per share divided by the reported Earnings per Share, multiplied by 100.

Dividend Yield -
Annualized Dividend per share divided by the market price per share of common stock reported, multiplied by 100.

Market/Book Ratio -
Market price per share of common stock reported, divided by the reported Book Value per share multiplied by 100.

Dividend/Book Ratio -
Annualized Dividend per share divided by the reported Book Value per share, multiplied by 100.

Price-Earnings Multiple Ratio -
Market price per share of common stock reported divided by the reported earnings per share.

Total Revenue - This is the total operating revenue for the latest 12 months as available. It includes regulated and non-regulated revenue.

% Electric / Gas / Water / Telephone Revenue -
Percentage of regulated revenues attributable to Elec./Gas/Water/Tele. operations relative to total Operating Revenue. Company groupings are based on revenue percentages and SIC classification criteria.

Net Plant -
Total Property, Plant and Equipment less Depreciation and Contributions in Aid of Construction for the latest quarter end figures available.

Net Plant Per Revenue -
Net Plant as reported divided by Operating Revenue as reported.

Standard & Poor's and Moody's Bond Ratings -
Ratings for each company's most senior long term debt security. For holding companies, ratings are based on an average of the bond ratings available for the regulated subsidiaries.

Common Equity Ratio -
Common Equity capital for the latest quarter divided by total capital as reported, multiplied by 100. Total capital is equal to the sum of long-term debt, current maturities, short-term debt, preferred stock and common equity for the latest quarter end figures available.

% Return on Book Value -- Common Equity -
Income Available for Common Equity divided by Average Common Equity, multiplied by 100. Average common equity based upon the most recent beginning and ending moving 12 month period available.

% Return on Book Value -- Total Capital From Continuing Operations -
Income before Interest Charges (inclusive of taxes) divided by Average Total Capitalization, multiplied by 100. Average total capitalization based upon the most recent beginning and ending four quarter values available.

Allowed R O E -
Most recent reported state-level allowed return rate on common equity (ROE). ROE for companies operating in multiple jurisdictions are averages. Various companies have received incentive-base ROE authorizations that are not reported upon in this report.

Order Date -
The date of the commission order authorizing reported ROE. For companies operating in multiple jurisdictions, no date is given because the reported ROE is an average derived from multiple commission orders issued at different times.

(NYSE) - New York Stock Exchange.

(ASE) - American Stock Exchange.

(NDQ) - NASDAQ.

NM - Not Meaningful.

NA - Not Available.

Additional Notes -

(1) Balance sheet values are the latest quarter end figures as available Income statement figures are for the latest 12 month available

(2) Based on per share value.

(3) Based on total capital. (The sum of long-term debt, current maturities, short term debt, preferred stock and common equity capital.)

(4) In many instances, available information require that Per Share and % Return on Book Value of Common Equity /Total Capital derived from figures that represent financial activity from different 12 month periods.

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IMPORTANT NUMBERS

GOVERNMENT AGENCIES

Federal Communications Commission (FCC)
445 12th Street S.W.
Washington D.C. 20554
(202) 418-0200
http://www.fcc.gov

Federal Energy Regulatory Commission (FERC)
888 First Street, N.E.
Washington D.C. 20426
(202) 208-0200
http://www.ferc.fed.us

Nuclear Regulatory Commission (NRC)
One White Flint North
11555 Rockville Pike
Rockville, MD 20852
(301) 415-7000
http://www.nrc.gov

Securities & Exchange Commission (SEC)
450 Fifth Street, N.W.
Washington D.C. 20549
(202) 942-7040
http://www.sec.gov

TRADE ASSOCIATIONS

American Gas Association (AGA)
400 N. Capitol Street, N.W.
Washington D.C. 20001
(202) 824-7000
http://www.aga.org

Edison Electric Institute (EEI)
701 Pennsylvania Ave., N.W.
Washington D.C. 20004
(202) 508-5000
http://www.eei.org

National Association of Water Companies (NAWC)
1725 K Street, N.W.
Suite 1212
Washington D.C. 20006
(202) 833-8383
http://www.nawc.org

United States Telecom Association (USTA)
1401 H. Street, N.W.
Suite 600
Washington D.C. 20005
(202) 326-7300
http://www.usta.org

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North America Major Publicly Traded Electric Utilities

YCharts Companies Data Overview

Companies		Market Cap	Shareholders Equity (Quarterly)	Total Long Term Debt (Quarterly)	Debt to Equity Ratio (Quarterly)	Equity Ratio
NextEra Energy Inc	$	57,625.38	22912	32408	1.4145	**41.4%**
Duke Energy Corp	$	56,958.57	39892	43793	1.0978	47.7%
Southern Co	$	46,904.64	20797	29678	1.427	41.2%
American Electric Power Co Inc	$	32,967.13	18126.5	21003.6	1.1587	46.3%
PG&E Corp	$	31,245.70	16612	17375	1.0459	48.9%
PPL Corp	$	26,427.94	9762	19824	2.0307	33.0%
CLP Holdings Ltd	$	24,632.89	12014.629	7158.7411	0.5958	62.7%
Edison International	$	24,106.77	11439	11901	1.0404	49.0%
Consolidated Edison Inc	$	22,805.32	13193	14160	1.0733	48.2%
Xcel Energy Inc	$	21,760.70	10671.634	13987.911	1.3108	43.3%
WEC Energy Group Inc	$	19,967.84	8818.3	10004.6	1.1345	46.8%
Eversource Energy	$	18,004.67	10438.499	10293.07	0.9861	50.4%
DTE Energy Co	$	16,901.02	8887	9573	1.0772	48.1%
Ameren Corp	$	12,431.39	6869	7597	1.106	47.5%
CMS Energy Corp	$	12,246.92	4109	9120	2.2195	31.1%
SCANA Corp	$	10,204.27	5539	6912	1.2479	44.5%
Fortis Inc	$	9,175.27	7464.7844	8718.2599	1.1679	46.1%
Alliant Energy Corp	$	8,826.09	3764.6	4049.5	1.0757	48.2%
Pinnacle West Capital Corp	$	8,622.24	4599.999	4082.412	0.8875	53.0%
Westar Energy Inc	$	7,942.65	3671.39	3619.12	0.9858	50.4%
TECO Energy Inc	$	6,509.42	2582.3	4086	1.5823	38.7%
OGE Energy Corp	$	6,178.78	3298.3	2816.8	0.854	53.9%
Great Plains Energy Inc	$	4,592.00	3650.9	4223.8	1.1569	46.4%
Idacorp Inc	$	3,779.14	2057.507	1868.797	0.9083	52.4%
Portland General Electric Co	$	3,771.17	2291	2199	0.9598	51.0%
Hawaiian Electric Industries Inc	$	3,657.48	1942.179	2003.184	1.0314	49.2%
				Average Equity Ratio of Parent/Holding Companies		**46.9%**