

October 6, 2009

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 4065 – National Grid Request for Change of Electric Distribution Rates
National Grid Rebuttal Testimony

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a National Grid¹, enclosed for filing, please find an original and nine (9) copies National Grid's Rebuttal Testimony in the above-referenced docket. This transmittal consists of rebuttal testimony of the following individuals:

- John Pettigrew
- Rudolph L Wynter, Jr.
- Susan F. Tierney, Ph.D.
- Paul R. Moul
- Julie M. Cannell
- William F. Dowd
- Robert L. O'Brien

Thank you for your attention to this transmittal. If you have any questions, please feel free to contact me at (401) 784-7667.

Very truly yours,



Thomas R. Teehan

Enclosure

cc: Docket 4065 Service List

¹ The Narragansett Electric Company d/b/a National Grid ("National Grid" or "Company").

Certificate of Service

I hereby certify that a copy of the cover letter and / or any materials accompanying this certificate has been electronically transmitted, sent via U.S. mail or hand-delivered to the individuals listed below.



Joanne M. Scanlon

October 6, 2009

Date

National Grid (NGrid) – Request for Change in Electric Distribution Rates
Docket No. 4065 - Service List as of 8/25/09

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National Grid

The Narragansett Electric Company

INVESTIGATION AS TO THE
PROPRIETY OF PROPOSED
TARIFF CHANGES

Rebuttal Testimony

Book 1 of 1

October 6, 2009

Submitted to:
Rhode Island Public Utilities Commission
Docket No. R.I.P.U.C. 4065

Submitted by:

nationalgrid

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
Docket No. R.I.P.U.C. 4065
Rebuttal Witness: Pettigrew

PRE-FILED REBUTTAL TESTIMONY

OF

JOHN PETTIGREW

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I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Mr. Pettigrew, please state your name and business address.

A. My name is John Pettigrew. My business address is 40 Sylvan Road, Waltham, MA 02451.

Q. Have you sponsored direct testimony in this proceeding?

A. Yes. My direct testimony was submitted in this proceeding with the Company's initial filing on June 1, 2009.

Q. What is the purpose of your rebuttal testimony?

A. I am submitting rebuttal testimony in response to the testimonies of Richard S. Hahn, Lee Smith, and David J. Effron sponsored by the Rhode Island Division of Public Carriers (the "Division").

Q. Would you summarize the specific areas covered by your rebuttal testimony?

A. Yes. My rebuttal testimony addresses recommendations made by the Division in relation to the following topics:

1. Contractual Commitments for Union Labor
2. Costs Associated with the Inspection & Maintenance Program
3. Costs Associated with Vegetation Management
4. Capital Forecast
5. Service Company Allocations

1 **II. UNION CONTRACT COMMITMENTS**

2 **Q. Would you first address Mr. Effron's recommendation on the Company's union**
3 **contract commitments?**

4 A. Yes. Mr. Effron recommends that the Company's adjusted test-year cost of service be
5 reduced by \$1,363,000 to eliminate the cost associated with union employees that will be
6 hired and on payroll before the end of calendar year 2010 (the rate year for this case).
7 Mr. Effron claims that the Company has not identified the tasks that these new hires will
8 be performing and, in fact, the employees will be hired in order to reduce the amount of
9 contract labor that is used by the Company (Effron Direct Testimony at 7).

10
11 **Q. Is Mr. Effron correct in the basis for his union labor adjustment?**

12 A. No. The amount of \$1,363,000 should not be eliminated from the Company's cost of
13 service because (1) the Company is contractually committed to these costs, (2) the
14 contractual commitment was made in order to institute a five-year ramp up of capital
15 work in the State of Rhode Island, and (3) the increased workload cannot be managed
16 without additional labor resources (both internal and external). Specifically, the
17 Company's capital work plan will involve an increased level of asset replacement and
18 other reliability-related work, such as load-relief projects. Increased labor will also be
19 needed to carry out the work plan for the Inspection and Maintenance ("I&M") Program.
20 The increased amount of work has been determined based upon the Company's
21 experience conducting a Feeder Hardening program in Rhode Island which although
22 similar to the I&M program is more limited in scope and volume. To manage this

1 increased work load, it was necessary for the Company to incorporate increased staffing
2 levels into the currently effective collective bargaining agreement in a way that was
3 coincident with the ramp-up of field work. Moreover, these incremental internal
4 resources will be needed in addition to – and not in the place of – external resources, as
5 Mr. Effron suggests. The Company anticipates that it will need to utilize additional
6 resources both internally and externally in order to complete the work plan. Since the
7 Company will engage these employees to perform (incremental) work on the system, and
8 since the cost is known and measurable under the terms of the collective bargaining
9 agreement, I must respectfully disagree with Mr. Effron that there is any reasonable basis
10 for the exclusion of these costs.

11
12 **Q. Has Mr. Effron made any other adjustments that you would like to address?**

13 A. Yes. Although he does not explicitly address it in his testimony, I understand that Mr.
14 Effron has eliminated the Company's proposed test-year cost of service adjustments
15 relating to the proposed I&M Program (\$2,094,000) and the Company's Vegetation
16 Management activities (\$1,985,000) (Schedule DJE-4). I believe that he has made these
17 adjustments on the basis of Mr. Hahn's testimony.

18
19 **III. INSPECTION AND MAINTENANCE PROGRAM**

20 **Q. Do you have any comment on Mr. Hahn's claims regarding the I&M Program?**

21 A. Yes, I do. Mr. Hahn recommends that the Commission eliminate the Company's post-
22 test year adjustment for operations and maintenance expense associated with the I&M

1 Program based on the claim that (1) the Company has not provided sufficient detail about
2 the inspection plan, in terms of the types of inspections and how inspections will differ
3 from what is done now (Hahn Direct Testimony at 7), and (2) the Company has not
4 demonstrated that the cost is incremental. I would like to respond to each of these claims.

5
6 **Q. Are you able to provide detail on the types of inspections that will be undertaken**
7 **through the I&M Program?**

8 A. Yes. The Company's Inspection & Maintenance Program is outlined in detail in the
9 document provided as Schedule NG-JP-R-1. Schedule NG-JP-R-1 outlines the types of
10 inspections that will be undertaken on various pieces of equipment, as well as identifying
11 the inspection cycle that will be applied to each asset category. For example, Schedule
12 NG-JP-R-1 shows that the Company's distribution system in Rhode Island encompasses
13 approximately 295,000 utility poles, which will be inspected on a five-year cycle, such
14 that 20 percent of the pole population (approximately 58,000 poles) is inspected each
15 year. Schedule NG-JP-R-1 also addresses the estimated cost of the inspection effort,
16 along with the Company's assessment of risk factors driving the need for and structure of
17 the I&M Program. The Company has identified the I&M Program to be a best practice
18 based upon actual experience gained through implementation in the Company's New
19 York service areas, as well as system-specific experience obtained through the Feeder
20 Hardening program, which the Company has utilized in Rhode Island for several years.
21 Consequently, contrary to Mr. Hahn's assertion that there is no sufficient detail to support
22 the program, the Company has expended considerable time evaluating, designing and

1 implementing the I&M Program for the benefit of Rhode Island customers who require
2 service reliability. Thus, the execution of the Inspection and Maintenance program will
3 yield positive results for Rhode Island customers that will permit the Company to meet its
4 reliability metrics and its regulatory obligation to provide safe and reliable service.
5

6 **Q. Would you explain whether the I&M Program is “significantly different” from what**
7 **is done now?**

8 A. Mr. Hahn’s recommendation that the Commission eliminate the cost adjustment for the
9 I&M Program is based, in part, on the premise that the activities to be conducted through
10 the I&M Program are not “significantly different” from the work plan that the Company
11 now follows (Hahn Direct Testimony at 7). However, Mr. Hahn is missing the nuance
12 that, while the *types* of asset-management activities conducted by the Company in the
13 past through the Feeder Hardening Program may be the same or similar to the types of
14 activities that will be conducted through the I&M Program, the Company has not
15 conducted those types of activities on the scale or with the systematized schedule that
16 will apply through the I&M Program. The difference in scale and schedule is significant
17 and is intended to have the direct effect of maintaining system reliability and creating the
18 opportunity for more cost-effective project completion.
19

20 **Q. Would you please explain how the I&M Program will differ in terms of scale?**

21 A. Yes. When I refer to a significant difference in terms of “scale,” I am referring to the
22 significant change in *the number inspections* that will be performed on a year-to-year

1 basis. Therefore, while Mr. Hahn may be correct in his basic assumption that the
2 Company has performed inspections on equipment components, such as overhead poles,
3 cross-arms, insulators, transformers and other distribution assets, in the past, the
4 Company has generally inspected those components only when a specific reason called
5 for an inspection. Beyond the Feeder Hardening Program, which involves limited
6 inspection and maintenance of a small subset of the system, the Company traditionally
7 utilized a fix-on-fail methodology to manage its assets. This methodology, however, is
8 reactive rather than proactive and is no longer a workable approach as the Company is
9 faced with managing an aged infrastructure. The transition to a formalized I&M Program
10 is a proactive way to evaluate the entire system every five years, providing the ability to
11 manage the aged assets and optimize their replacement while maintaining reliability for
12 customers. Moreover, the Company has not historically inspected all components within
13 an asset class to assess their condition and plan for cost effective retirements. The I&M
14 Program provides for the inspection and maintenance of all overhead, underground, and
15 sub-transmission line assets, on a cyclical basis rather than being dictated primarily by
16 (non) performance issues. Because all components encompassed in a distribution asset
17 class are included in the inspection and maintenance program, the number of inspections
18 (and related maintenance) that will be completed is significantly greater than the number
19 completed utilizing the fix-on-fail methodology. In terms of order of magnitude, the
20 Company traditionally inspected and maintained 350 miles of the Rhode Island overhead
21 system annually under the Feeder Hardening Program. Going forward, the Company
22 would inspect and maintain 1,000 miles of the Rhode Island overhead system annually

1 through the I&M program, for an increase of approximately 300 percent annually.

2
3 **Q. Would you please explain how the I&M Program will differ in terms of schedule?**

4 A. Yes. When I refer to a significant difference in terms of “schedule,” I am referring to the
5 significant change in the *timing of inspections* that will be performed on distribution asset
6 components. Specifically, through the I&M Program, the Company plans to institute
7 systematic inspection and maintenance of all overhead, underground and sub-
8 transmission line assets on a five-year cycle with 20 percent of the system completed
9 each year. Prior to the implementation of the I&M Program, systematic inspections were
10 not conducted as part of the Annual Work Plan because work activities, including
11 inspections and maintenance activities, were generally scheduled on a component-by
12 component basis in response to deficient operating performance or component failure.
13 As a result, distribution assets may not be inspected for long periods of time so long as
14 those components were not exhibiting any performance issues. Thus, the underlying
15 philosophy of the I&M Program is to assess the condition of distribution assets or asset
16 systems on a class-specific or system-specific basis and to structure a proactive
17 replacement plan for each asset or asset system. Ultimately, the revised approach will
18 create a longer-term planning horizon that will provide the opportunity for more efficient
19 procurement and allocation of needed resources. It will also create a higher level of
20 discipline in maintaining the system. In the meantime, the approach represents a
21 significant shift from past practice, which will involve substantial incremental work as
22 compared to the test-year level. As previously mentioned, the volume and scope of work

1 identified to be conducted as part of the I&M program was determined using actual data
2 captured through the Feeder Hardening Program, coupled with the Company's extensive
3 experience in its New York service area. The Company has determined that this program
4 is necessary to meet the reliability needs of customers as encompassed in the reliability
5 metrics established for the Company in Rhode Island.
6

7 **Q. Do you have a response to Mr. Hahn's claim that the I&M Program costs should be**
8 **eliminated because the costs are not "truly incremental" to the test-year level of**
9 **expense?**

10 A. Yes I do. Mr. Hahn claims that the Company has not demonstrated that "all of the costs
11 of this program are truly incremental" (Hahn Direct Testimony at 7). Although Mr. Hahn
12 does not define his use of the term "incremental," his statement implies that, so long as
13 the Company incurred some level of cost in the test year for activities that may be
14 undertaken through the I&M Program, no costs incurred through the rate year could be
15 considered incremental and eligible for recovery through rates. I disagree with this
16 definition of incremental. Although the I&M Program will subsume the Feeder
17 Hardening Program, the number of inspection and maintenance activities that will be
18 undertaken through the I&M Program through the rate year are incremental to the
19 number of activities performed in the test year and differ from the test year in substantial
20 amount. Therefore, while the test-year spending amounts include spending through the
21 Feeder Hardening Program, as well as the cost of other activities undertaken in the test-
22 year to maintain the system, it does not include the cost of the full scale and scope of

activities that will occur through the I&M program. Consequently, the cost of the incremental activities that would be performed through the I&M Program is “truly incremental” to the test-year level of cost and should be included in the Company’s rate year revenue requirement and is coincident with an increase in volume of work.

Q. Would you please review the Company’s request for cost recovery associated with the I&M Program in this proceeding?

A. The Company is requesting that the Commission adjust the test-year level of O&M expense by \$2,094,000. As represented in my Direct Testimony, Schedule NG-JP-1, this amount represents the known and measurable cost of completing the ramped-up level of annual inspections and maintenance activities that will be completed through the end of the rate year (\$4.7 million), less the amount incurred in the test year. The Company is also proposing to include this incremental amount of \$2,094,000 in its rate year revenue requirement, and then to recover actual annual inspections and maintenance expense activities in excess of the total expected annual amount of \$4.7 million through a reconciliation mechanism. As shown in Schedule NG-JP-R-1, the Company believes that the value of the I&M Program for customers will be substantial in terms of maintaining a high level of reliability and managing the system assets proactively, and therefore, the costs are warranted for inclusion in rates.

IV. VEGETATION MANAGEMENT

Q. Would you please address Mr. Hahn’s recommendation as to the elimination of

costs associated with the Company's Vegetation Management Program?

A. Yes. Mr. Hahn is recommending that the Commission eliminate the Company's proposed adjustment for Vegetation Management expenses totaling \$1,985,000 from the adjusted test-year cost of service (Hahn Direct Testimony at 9). However, in making this recommendation, Mr. Hahn has not addressed the fact that the Company has made a substantial and permanent change to its vegetation management approach, which is not captured in the test year and that, therefore, makes the test year non-representative in terms of the cost of vegetation management activities. The Company submitted a detailed analysis of its vegetation management activities as Attachment DIV-14-1-1, which Mr. Hahn has not discussed in his testimony. However, the crux of the discussion is that National Grid has enhanced the program in two significant ways: first, hazard tree removal is utilizing a formal hazard tree mitigation program, which was built using a risk analysis protocol, including hazard tree specifications, and intensive field training. This program allows for an unacceptable level of risk to be set and clearly defined. Through an industry leading risk ranking protocol, the actual level of risk can be determined in the field and mitigated appropriately. This ensures consistent, appropriate allocation of funding, and allows for specific targeting of high risk trees in high risk areas, which are areas of a circuit affecting the most customers, thus providing maximum reliability benefit. Second, a new contract strategy method was executed to ensure market value prices for vegetation management activities. This strategy fosters competitive pricing from multiple bidders for a defined scope of work. Vendor risk is minimized by allowing an extension of the contract, based on acceptable levels of key performance indicators.

1 By paying actual market value, utility risk from vendor default is minimized. Most
2 importantly, this ensures program integrity, but also keeps the local vendor workforce
3 stable, which in turn has pruning quality and safety value. These changes will have
4 important reliability and public safety ramifications, but also will involve more cost. Mr.
5 Hahn's testimony does not address any of these changes. However, these discrete and
6 permanent changes are not reflected in the test year cost data, and therefore, the test year
7 cost data is non-representative of the Company's actual cost of vegetation management
8 activities through the rate year.
9

10 **Q. Would you please review the Company's request for cost recovery associated with**
11 **Vegetation Management activities in this proceeding?**

12 A. The Company is requesting that the Commission adjust the test-year level of O&M
13 expense by \$1,985,000. As represented in my Direct Testimony, Schedule NG-JP-2, this
14 amount represents the known and measurable cost of completing the vegetation
15 management activities through the end of the rate year (\$9.084 million), less the amount
16 incurred in the test year (\$7.037 million). The Company is also proposing to include the
17 amount of \$1,985,000 in the base revenue requirement as a known and measurable
18 change to the test-year cost of service. The Company believes that the vegetation
19 management approach it has adopted will benefit customers in terms of achieving its
20 reliability requirements because tree-related outages are the leading factor of outages on
21 the system, and therefore, the costs are warranted for inclusion in rates.
22

1 **Q. Is the Company proposing a reconciliation mechanism for the recovery of**
2 **vegetation management expenses following the implementation of new rates in this**
3 **proceeding?**

4 A. No. In my direct testimony, the statement was made that the going-forward vegetation
5 management costs incurred in excess of the amount included in base rates in this
6 proceeding would be reconciled through the I&M tracking mechanism (Pettigrew Direct
7 Testimony at 61). However, this was simply a mistake made in the production process
8 and the Company is not making that proposal.

9
10 **V. CAPITAL FORECAST**

11 **Q. Would you next address the Division's recommendation to exclude \$20,222,000 of**
12 **forecasted capital additions from the adjusted test-year cost of service?**

13 A. Yes. The Division recommends that the Commission reduce the amount of rate base
14 included in the adjusted rate-year cost of service by \$20,222,000 (Effron Direct
15 Testimony at 29). Mr. Effron states that his adjustment arises from the fact that the
16 Company's forecast of capital additions through the rate year (2010) is 25 percent greater
17 than forecast for 2009, and 58 percent greater than the actual rate of plant additions for
18 the first seven months of 2009. Mr. Hahn questions the need for the ramp-up in capital
19 that the Company is projecting for reliability purposes. To respond to these assertions, I
20 will first address Mr. Hahn's claims regarding the need for the ramp-up in capital
21 spending, and then I will address Mr. Effron's more specific recommendation regarding
22 the level of capital spending that will occur through the rate year.

1 **Q. What is your response to Mr. Hahn's suggestion that additional investment is not**
2 **needed to maintain the Company's infrastructure at this time?**

3 A. I disagree with Mr. Hahn's conclusion based on the significant amount of study that the
4 Company has performed to identify and plan for system-investment requirements.
5 During the budget process, each category of capital spending is closely analyzed to derive
6 the forecast amount. For example, one category of capital spending is "Load Relief."
7 Load Relief projects are generally identified as a result of evaluation of (and adherence
8 to) applicable planning criteria and may include major projects such as new substations
9 or large-scale rebuilds or other projects to address step-down transformer limitations (for
10 example). Load relief projects account for approximately 17 percent of the total capital
11 budget in calendar year 2010. The increased investment for Load Relief projects is
12 arising from the following project categories.

- 13 ♦ Substation Capacity Related Projects – approximately \$5.8 million
- 14 ♦ Distribution (line) Transformer Replacement Program – approximately \$1.2
15 million
- 16 ♦ Distribution Line Re-conductoring – approximately \$1.7million

17
18 Similarly, Asset Replacement Projects account for approximately 22 percent of the total
19 2010 forecast capital budget. The increased investment for Asset Replacement Projects
20 is arising primarily from the following project categories.

- 21 ♦ Projects identified through the I&M Program – approximately \$6.1 million
- 22 ♦ Substation Asset Replacement Programs – approximately \$6.2 million

- 1 ♦ Conductor and underground cable replacement programs – approximately
- 2 \$600,000 combined
- 3 ♦ Duct & Manhole Replacements – approximately \$1.3 million

4

5 All of these planned projects are related to the issue of the need to replace aged

6 distribution assets.

7

8 It should be noted that the investment in the system that the Company is proposing in its

9 forecast is designed to maintain the system to meet the needs of our customers and

10 provide reliability consistent with the targets set forth by the State. In addition to the

11 targeted programs mentioned above, the Company is required to complete non-

12 discretionary work referred to as Regulatory/Mandatory programs. These programs

13 represent more than 20 percent of the forecast budget and are necessary to meet the

14 specific needs of customers as defined by the Company's franchise agreement.

15

16 **Q. Would you please discuss the age of electrical distribution assets on the Company's**

17 **Rhode Island system and the impact of age on capital budgeting?**

18 A. Yes. A significant portion of the Company's distribution assets are older than 30 years,

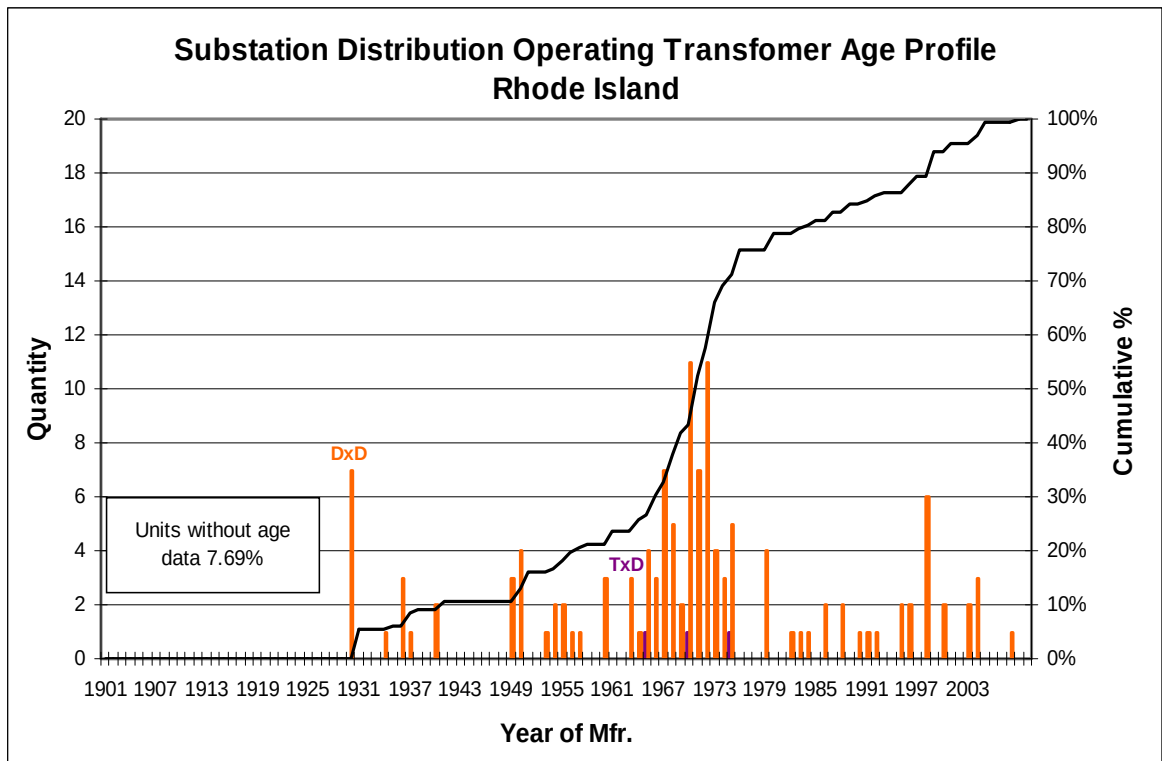
19 and with the typical rate of replacement, the volume of assets with an age greater than 30

20 years only continues to increase. With this increased level of aged assets, the Company

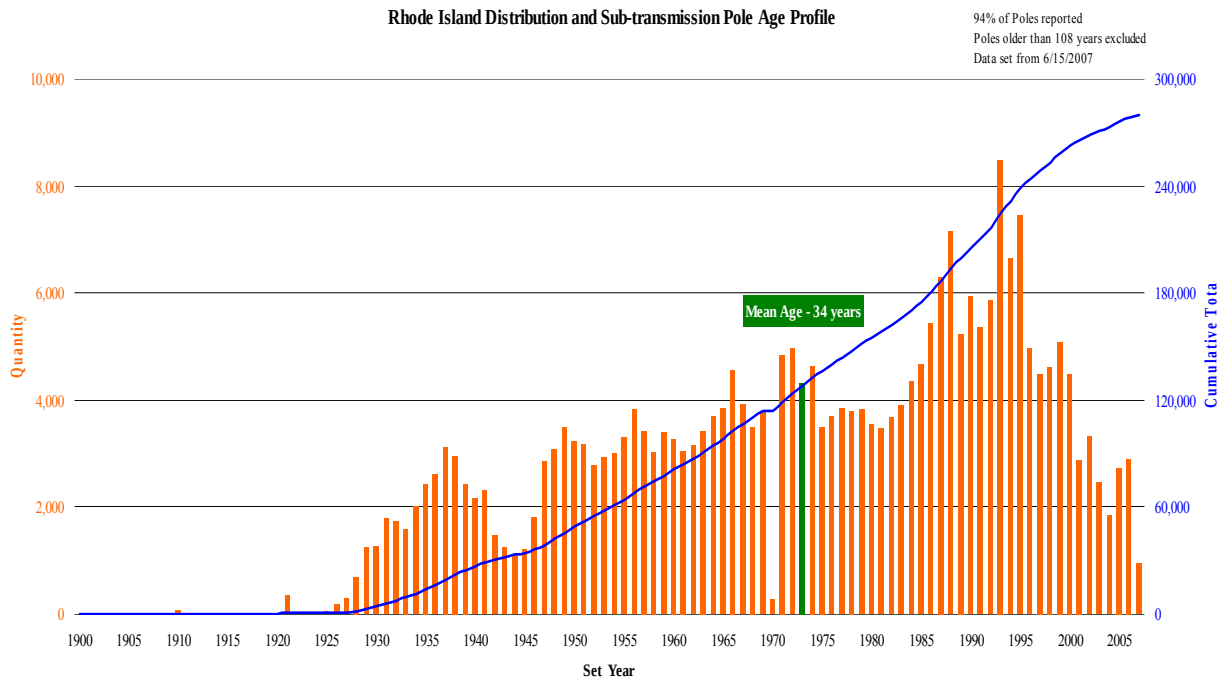
21 anticipates that "end of life failures" will increase. Regarding these assets, it is generally

22 accepted that there is a low probability of failure during most of their operating lifetime,

with a noticeable increase in failure probability over the last quarter of their lives. Accordingly, the Company's ability to meet capacity needs and at the same time maintain system reliability with the increasing number of aged assets will be compromised in future years unless more aggressive replacement efforts are taken. Therefore, equipment age is a significant factor in crafting the annual budget. The following charts illustrate the asset age issue:



Station Transformer Age in years	Percentage of Population	Count
>20 yrs	85.31%	122
>30 yrs	80.42%	115
>40 yrs	47.55%	68
>50 yrs	27.27%	39
>60 yrs	19.58%	28
>70 yrs	16.08%	23



Pole Age in years	Percentage of Population	Count
>20 yrs	71.24%	199,260
>30 yrs	54.18%	151,550
>40 yrs	40.71%	113,860
>50 yrs	27.77%	77,660
>60 yrs	16.31%	45,600
>70 yrs	8.90%	24,890

It should be noted that, while the *average* age of an asset class may not seem excessive, the spread of ages within the population covers many decades. When the assets were originally installed, the expected life was generally considered to be 30-50 years, which is viewed within the electric distribution industry as creating an “asset wall” based on the expected design life. The “asset wall” concept represents the phenomenon of a need to replace a large number of assets over a relatively small period of time. Attrition due to failures and early replacement due to capacity issues has had some effect in reducing the

1 potential “asset wall” for National Grid; however, more work is needed to alleviate
2 potential reliability problems. Although age of assets is a reasonable proxy for replacing
3 assets the I&M Program is specifically designed to establish a condition-based approach
4 for asset replacement, which will enable the replacement of assets based on a “technical
5 asset life” and target those assets that pose the greatest risk to the system.

6
7 Another important consideration is that, as distribution assets age and deteriorate, failures
8 may accelerate to the detriment of both safety and reliability considerations. Although
9 age is not dispositive of the usefulness of a distribution component, age is a useful proxy
10 to indicate which assets will be less able to perform their function through accumulated
11 deterioration, obsolescence or insufficient capacity. A good example of a significant
12 piece of equipment where age is a reasonable proxy for identifying potential replacement
13 candidates is our power transformers at substations. Power transformers provide service
14 to many thousands of customers and represent the single largest capital investment in
15 substations, comprising *a significant portion of the Company’s asset rate base*. Power
16 transformers deteriorate with time and thermal operation because paper is a key
17 component of the insulation used between the windings of a transformer. This paper
18 suffers deterioration as a result of three processes: oxidation, hydrolysis and thermal
19 heating. The deterioration is cumulative and irreversible and thus cannot be addressed
20 through maintenance procedures.

1 **Q. What is your concern with respect to Mr. Hahn’s suggestion that the Company does**
2 **not need to replace aged assets on an accelerated schedule.**

3 A. Failure to replace assets that need to be replaced creates at least two basic concerns: one
4 associated with low-cost, large-volume assets and the other with high-cost, lower-volume
5 assets. Regarding the low cost items, failure to replace these assets in a timely manner
6 will result in a huge number of assets that are so aged that the volume of assets to be
7 replaced at some point in the future will be insurmountable. For instance, the Company’s
8 utility pole base is approximately 295,000. The Company presently replaces
9 approximately 450 poles annually under its pole replacement strategy. However, nearly
10 78,000 of the current pole population is older than 50 years. Thus, at the current
11 replacement rate – assuming the Company replaces poles in the age category of greater
12 than 50 years for the next 30 years, the Company will still have approximately 64,000
13 poles greater than 80 years old and nearly 138,000 greater than 60 years old.
14 Accordingly, the ability for the Company to safely and reliably operate its system with
15 this type of age distribution will be compromised. Furthermore, the replacement
16 schedule necessitated by this type of distribution of assets will not be tenable.
17 Likewise, for high-cost, lower-volume assets, failure to replace these assets in a timely
18 manner will result in significant and various challenges to replace these assets when they
19 fail due to the complexity and cost associated with these assets. For instance,
20 approximately 45 percent of the Company’s approximately 150 substation transformers
21 are older than 40 years. Thus, if the Company replaced two substations per year (each in
22 this age grouping), in 20 years, the Company would still have approximately 20 percent

1 of its transformers (or 28 units) that would be greater than 60 years old. In total, the
2 Company would have nearly 75 units (or approximately 50 percent) with an age greater
3 than 50 years old. In addition to creating safety and reliability concerns, this type of a
4 situation would impair the Company's ability to efficiently and effectively replace the
5 large number of complex assets and the capital and O&M and manpower resources that
6 would be needed would represent a significant challenge.
7

8 **Q. What about Mr. Hahn's claim that the Company's "current high level of reliability"**
9 **shows that additional capital investment is not needed.**

10 A. Based on the Company's detailed analysis of its system and the age of its distribution
11 infrastructure indicates to the Company that current levels of reliability cannot be
12 maintained without additional capital investment. Efforts to maintain the safety and
13 reliability of the electric system cannot and should not be undertaken only at such time
14 that reliability problems are experienced by customers.
15

16 Continuing to provide the level of service that is presently experienced by customers
17 requires, among other things, a balance between maintaining the system, making
18 appropriate investments when necessary, replacing assets in a timely manner and meeting
19 the obligation to ensure adequate supply capabilities are available. The forecast set forth
20 by the Company is designed to achieve these needs in a responsible manner. The level of
21 reliability that is experienced by our customers is indicative that the Company has been
22 making the appropriate level and types of investment in the system. Using its experience

1 and knowledge of the system, the Company has developed the forecast to continue to
2 meet the needs and expectations of its customers.

3
4 **Q. What is your response to Mr. Effron's recommendation that \$20,222,000 in capital**
5 **investment should be excluded from the rate base used to set the revenue**
6 **requirement?**

7 A. Mr. Effron arrives at this recommendation based simply on the theory that the forecast
8 level of spending is greater than the past (Effron Direct Testimony at 29), although his
9 recommendation is based largely on the rate of actual spending occurring in 2009 to date.
10 I should point out that, although the Company has presented capital budget figures on a
11 calendar year basis for the purposes of the Commission's ratemaking exercise, the
12 Company's budget cycle runs from April through March of each year. As a result, Mr.
13 Effron's review of spending in the months January through July 2009 does not capture
14 the Company's full fiscal year spending trend. By way of comparison, the Company's
15 actual spending trends in terms of Fiscal Year budgeted amounts to Fiscal Year actual
16 spending for the past several years are as follows:

	FY2006	FY2007	FY2008	FY2009
Budget [N.1]	\$43,944,500	\$48,769,375	\$53,547,000	\$57,765,000
Actual [N.1]	\$45,839,376	\$51,359,609	\$57,963,472	\$55,293,302
Variance	\$1,894,876	\$2,590,235	\$4,526,472	(\$2,471,698)
[N.1] Excludes Public Requirement Projects				

17
18 This table shows that the Company's actual spending has generally exceeded the
19 forecasted budget on a full fiscal year basis.

1 **Q. What is the reason that capital spending currently appears to be lagging behind the**
2 **budget amount for FY2010?**

3 A. The Company is currently under-budget by approximately \$7 million in relation to its
4 fiscal year budget for fiscal year 2010, due largely to a large substation project and its
5 associated work in Newport, Rhode Island, which is currently experiencing delays in
6 acquiring the real estate necessary for the substation. Additionally, the scheduling and
7 execution of other normal work is also contributing to the present under-run. However,
8 the Company is focused on completing this capital work and my expectation is that the
9 capital forecast will be fulfilled. Therefore, I do not see any basis for Mr. Effron's
10 adjustment to rate base.

11
12 **VI. SERVICE COMPANY ALLOCATIONS**

13 **Q. Would you please respond to the Division's recommendation that the Commission**
14 **disallow approximately \$2.3 million in costs from Account 583 relating to the**
15 **Company's Geographic Information System ("GIS") costs on the basis that the costs**
16 **in the test year are not representative of costs that will be incurred in the future.**

17 A. Yes. Ms. Smith claims that the Company's going forward GIS expense will be less than
18 the 2008 expense and will be reduced to zero by 2010. This is not correct. Although the
19 costs of the Company's GIS program do vary somewhat from year to year, the costs
20 incurred during the test year are representative of the costs the Company will incur on an
21 ongoing basis. This is because the costs incurred by the Company in 2008 relate to the
22 *NE Overhead GIS Survey* project, which is a process to update data used in the

1 Company's GIS system in relation to the Company's overhead distribution system.

2 While this particular project was completed in June 2009, the Company has already
3 commenced a new *Underground* GIS Survey pilot project, which is a precursor to a
4 significant multi-year project that will update or "true up" the Underground GIS data.

5 This type of activity is routine for the Company and is a necessarily undertaken on a
6 periodic basis to bring systems in line with updated actual information. As a result,
7 expenditures on this project will be significant in 2010 and will continue into future
8 years. Thus, Ms. Smith's allegation that the GIS expenses are non-recurring in nature is
9 not accurate.

10
11 **Q. Please describe the Company's GIS system and the nature of the expenses criticized**
12 **by Ms. Smith.**

13 A. Generally, a GIS system is a database used to capture, store, analyze, and manage spatial
14 data, which is linked to a specific geographic location. In order for a GIS system to
15 function properly, the data in the system must be accurate. Among other things, GIS is a
16 mapping database that models the electrical network and customer connections and is
17 utilized extensively by control center personnel through an Outage Management System
18 to operate the system and restore customers in a timely manner when an outage occurs.
19 Furthermore, the GIS system is instrumental during large power outages in order to
20 quickly identify the scope of the event and allow emergency planning personnel to
21 respond appropriately and effectively. The costs criticized by Ms. Smith (and in Account
22 583) are associated with the New England Overhead GIS Survey, which was the first

1 phase of a long term project. In this initial phase, the Company conducted a field survey
2 of its overhead facilities, and input that data into its GIS system. The Underground GIS
3 data survey will occur in essentially the same manner, as will future data surveys that will
4 be planned and implemented from time to time to ensure that data relied on by the
5 Company in using its information systems are up-to-date and accurate.
6

7 **Q. Please describe why the expenses in Account 583 are recurring.**

8 A. The Company's GIS data plays an important role in the day-to-day operations of the
9 Company and is critical to the provision of safe and reliable service. For this reason, the
10 Company must continually work to ensure the accuracy of data residing in the system
11 through frequent survey efforts, such as that identified by Ms. Smith. Consequently, the
12 Company will continue to incur costs associated with GIS data acquisition and
13 correction. Thus, Ms. Smith's claim that the GIS expense incurred in the test year is non-
14 recurring is incorrect.
15

16 **Q. Ms. Smith also recommends that the Department disallow approximately \$800,000**
17 **in costs in Account 588 related to the Electricity Distribution Transformation**
18 **Program unless the Company provides evidence that: 1) the program provides net**
19 **benefits for the Company, and 2) that the program could not have been performed**
20 **at less cost. Please explain why this cost should not be reduced.**

21 A. This expenditure should not be reduced because the result produced by these
22 improvements will be captured in future rate cases, and therefore, will inevitably inure to

1 the benefit of customers. It would simply be arbitrary to remove these costs from the cost
2 of service, when they are incurred on behalf of customers to contain costs and achieve
3 process effectiveness. All levels of the National Grid organization are engaged in this
4 effort to establish a streamlined business model that is based on a performance-driven
5 culture with the deployment of best practices. This is the type of analysis and innovation
6 that the Commission should want to promote in the long-term interests of customers.
7

8 **Q. Did the Company take steps to implement cost effective changes and to contain**
9 **transformation costs?**

10 A. Yes. The transformation program was performed at the lowest cost by following
11 competitive bid processes, using strong project management skills, processes and
12 capabilities, and ensuring strong fiscal discipline and tracking of all costs and benefits.
13 Additionally, the Company relied upon its strong governance processes to provide
14 oversight. This project utilizes a Steering Committee that meets monthly and other
15 governance bodies in support of running an efficient and effective project. I am the
16 project sponsor identified in our governance process. Lastly, the Company utilized a
17 third party consultant to support the program, provide key industry insights, bring best
18 practice experience, and provide project management expertise. Consistent with
19 Company requirements, this was done through a formal tender and bid process, overseen
20 by our procurement organization and following our procurement guidelines. As a result,
21 there is no basis for excluding these costs.
22

1 **Q.** **Does this conclude your testimony?**

2 **A.** Yes, it does.

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Strategy Statement

The intent of this strategy is to provide an approach for a comprehensive Inspection and Maintenance (I&M) program for Distribution Overhead, Underground, and Sub Transmission line assets. This program will include visual, aerial, infrared inspection and elevated voltage testing.

This strategy is designed to both meet regulatory requirements in all states and provide for a sustainable distribution and sub-transmission system.

Based on the results of this inspection program, budgets can be adjusted to allow for the timely replacement of the required plant.

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
1	09/09/2009	Initial Issue	Mohamed H Shamog Distribution Asset Strategy	John Pettigrew Executive Vice President, Electric Distribution Operations Chairman of DCIG

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Strategy Justification

1.0 Purpose and Scope

The intent of this strategy is to provide an approach for a comprehensive inspection program for Distribution Overhead, Underground, and Sub Transmission line assets. This program will include visual, aerial, infrared inspections and elevated voltage testing.

2.0 Strategy Description

2.1 Background

National Grid's electric distribution and subtransmission assets are extensive. National Grid has over 70,000 circuit miles of distribution overhead, underground, and subtransmission lines, which serve approximately 3.3 million customers in four states: Massachusetts, New Hampshire, New York and Rhode Island. The breakdown of the major assets by state is listed in Table 1.

	NY	MA	RI	NH	Total
Primary Miles:					
Distribution					
Overhead	35,874	13,708	4,974	681	55,237
Underground	7,454	4,907	1,058	211	13,630
Subtransmission					0
Overhead	3,169	570	310	45	4,094
Underground	unknown	530	140	5	675
Poles	1,232,152	716,541	294,867	36,641	2,280,201
Manholes	16,804	22,317	5,097	331	44,549
Vaults	1,802	1,685	1,032	116	4,635
Transformers:					
Overhead	380,057	157,263	67,459	7,584	612,363
Underground					
- Padmount	46,174	31,224	7,592	1,640	86,630
- Other underground	19,577	4,380	1,263	126	25,346
Step-down	14,570	2,565	274	62	17,471
Cutouts	252,564	275,895	105,114	13,273	646,846
Switchgear	3,084	848	222	17	4,171
Reclosers	888	997	308	52	2,245
Regulators	3,404	155	52	9	3,620
Capacitors	4,711	2,535	953	87	8,286
Sectionalizers	51	24	2	1	78
Switches:					
Overhead	66,041	18,530	9,588	684	94,843
Underground	773	1,714	458	6	2,951
Undefined structures	74	33	5	6	118

Table 1: National Grid Asset Statistics¹

¹ All the information obtained from SDE data base (as of April, 2009)

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The major influences on National Grid's reliability performance are typically trees, animals, lightning and deteriorated equipment². The Reliability Enhancement Program (REP) was developed to address this trend. The REP program consisted of four major initiatives:

1. Feeder Hardening/Engineering Reliability Reviews
2. Incremental Asset Replacement
3. Incremental Vegetation Management
4. Inspection and Maintenance

The goal of the REP was to meet state regulatory targets for reliability and attain National Grid internal performance targets. The Inspection and Maintenance Strategy will replace programs within the REP such as Feeder Hardening and some of the distribution line asset replacement programs. The I&M Program builds on lessons learned from REP and will be an ongoing program. This cyclical inspection and maintenance program plays a significant role in having a sustainable and reliable system as well as meeting regulatory requirements for inspections in Massachusetts and New York. Currently there are no regulatory requirements in New Hampshire and Rhode Island

2.2 Strategy

The I&M Strategy is a comprehensive inspection and maintenance program for overhead and underground distribution and subtransmission assets. A key point of this program is that each asset in the underground and overhead system will be inspected at least every five years meaning that approximately 3.9 million assets will be visually inspected every 5 yrs. The strategy will drive a consistent inspection approach in all states National Grid serves and benefit customers by ensuring the distribution and subtransmission systems are sustainable and reliable. The Inspection and Maintenance program is a set of best practices adopted from within National Grid. This program was instituted in NY in 2005 and each year benefits of the program have been realized. Improvements in the quality of data collection have improved our knowledge of assets within the system so we can make better decisions to better serve customers.

The I&M strategy recommends a cyclical inspection and maintenance program. The inspection priority system will identify and provide for the timely condition-based replacement of any visibly damaged or deteriorated assets prior to the next inspection cycle. The following is a brief description of the inspection program:

Any work identified as a result of the Inspection and Maintenance program will be prioritized based on the severity of the issues found. Priority Codes are as follows:

- Level 1³ - Must be repaired/replaced within one week
- Level 2⁴ - Must be repaired/replaced within one year

² Refer to Feeder Hardening Strategy

³ An immediate issue that requires the inspector to stand-by until a qualified crew/supervisor arrives to resolve the issues as soon as practical, but no longer than 1 week.

⁴ An issue that, if left unresolved, has a high probability of failure within 1 year of the feeder inspection. Either the identified work will be completed within 1 year or a project will be initiated to complete the work in a timely fashion (e.g., pole replacement or addition may require permits or DOT involvement that may require longer than 1 year to complete.).

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Level 3⁵ - Must be repaired/replaced within three years

Level 4⁶ - Information only, replace based on engineering judgment and budget availability

The inspection system is linked to the work management system for streamlined work order creation, execution, field completion, closeout and tracking.

On an annual basis, the inspection criteria shall be reviewed for effectiveness and adequacy with representatives from the following departments; Asset Strategy, Network Asset Planning, Inspections, Safety, Operations, Standards and any other stakeholders deemed appropriate.

A Quality Assurance/Quality Control program is required for New York and shall be implemented in all states to insure the efficiency and effectiveness of the inspection and maintenance program.

Line assets across the system shall be inspected as follows:

2.2.1 Overhead Distribution Inspection

- Five-year cycle visual inspection of overhead assets, which at a minimum will include poles, crossarms, insulators, primaries, transformers, capacitors, regulators, switches, reclosers, ground, guys, anchors, secondaries, services, spacer cable, cutouts, risers, switch gears, padmounted transformers, enclosures, and right of way (R.O.W).
- Five-year cycle infrared inspection on overhead mainline circuits
- Semi-Annual Feeder Patrols

2.2.2 Underground Distribution Inspection

- Five-year cycle visual inspection of underground assets, which at a minimum will include metallic handholes, padmounted transformers, switchgears, manholes, vaults, splice boxes, junction boxes, and submersible equipments.
- Five-year cycle internal inspections of padmounted transformers and switch gears
- Five-year cycle infrared inspection of all separable components

2.2.3 Subtransmission Line Inspection

- Five-year cycle visual inspection of overhead assets, which at a minimum will include towers, poles, crossarms, insulators, switches, reclosers, sectionalizers, conductors, guys, anchors, risers, R.O.W, and foundations.
- Annual aerial helicopter patrol for visual examinations
- Three-year cycle aerial Helicopter Infrared Patrol

⁵ An issue that has a high probability of failure within 3-5 years of the feeder inspection. Either the identified work will be completed within 3 years, or a project will be initiated to complete the work. These issues may require permitting and or significant design/engineering/construction and may need to be budgeted to complete.

⁶ This information will be used for asset decision making and to aid inspectors during the subsequent inspections.

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2.2.4 Elevated Voltage Testing

Elevated voltage testing shall be conducted on all utility facilities that are capable of conducting electricity and are publicly accessible which include:

- Substation Fences
- Overhead distribution facilities
- Subtransmission facilities
- Underground facilities
- Street Lights
- Daily work area

Due to regulatory requirements, elevated voltage testing shall be performed based on the state requirements but no longer than a 5 year cyclic testing on all equipment. Refer to the Appendices for state specific requirements.

2.2.5 Street Light Standards

Street light standards inspection shall be performed on all street lights as part of the inspection program. The inspection shall include at a minimum:

- Luminaries
- Arms
- Standards
- Foundations
- Conductors

The inspection is based on a five-year cycle such that 20% of the inspection should be scheduled on an established annual basis.

2.2.6 Regulators/Capacitors

Regulators and Capacitors shall be inspected annually to determine operability and general condition.

2.2.7 Reclosers/ Sectionalizers

Reclosers and sectionalizers shall be inspected every 6 months. Recloser outages typically involve large number of customers so an appropriate level of maintenance is needed to offset the higher risk of misoperations and failures.

2.2.8 Fast Feeder Patrols

A fast feeder patrol is an assessment to identify and fix immediate problems on overhead distribution feeder main line construction from the substation breaker to fused 3 phase side taps ($\geq 65K$ fuse). The patrol will exclude all underground constructions as well as all fused laterals. Feeder patrols are currently used by all divisions in an informal means to respond to reliability concerns throughout the year. Fast Feeder patrol shall be performed semiannually for all main line overhead distribution feeders.

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3.0 Benefits

3.1 Safety & Environmental

Asset replacement prior to failure provides incremental employee and public safety benefits and avoidance of potential environmental problems related to some assets i.e. transformers and poles. In addition, implementation of this strategy addresses safety concerns relating to elevated voltage on all publicly accessible facilities.

3.2 Reliability

Condition based repair/ replacement will result in improved reliability and support the creation of a sustainable system. Collectively deteriorated equipment related interruptions are one of the main drivers of poor reliability. The high impact deteriorated equipment problems currently addressed by the Feeder Hardening Program will be extended to a larger group of assets.

3.3 Customer/Regulatory/Reputation

The main customer benefits from this strategy are elimination of an elevated voltage hazard, improved reliability, and the creation of a sustainable system. Additionally, condition based replacement will support the attainment of our regulatory targets. The combination of cyclical inspections and replacing equipment as it is required leads to having a sustainable system that should be supported by state regulator.

4.0 Estimated Costs

The cost estimates proposed in this strategy include both incremental costs to perform the inspections as well as all the costs associated with completing the generated work from inspection in the appropriate time lines. The cost estimates for the work generated from inspections were derived based on our experience from NY I&M in 2008 as well as the feeder hardening program in NE. Please refer to Appendixes F & G for all cost details.

5.0 Implementation

The high impact deteriorated equipment problems are currently being addressed by the Feeder Hardening Program. Starting in FY09, equipment identified as part of the revised inspection program has extended the Feeder Hardening benefits on a smaller scale to a larger group of assets across National Grid. The inspection program will replace the Feeder Hardening program after the initial five year (FY07-FY11) plan has been completed.

- Level 1 items require immediate replacement in the current fiscal year.
- Level 2 items require replacement within one year cycle.
- Level 3 items will provide a baseline for budgeting over the next two fiscal years.

Additionally, Problem Identification Worksheets (PIW), Feeder Hardening, Engineering Reliability Reviews and Pockets of Poor Performance will continue to identify additional miscellaneous overhead replacement work until I&M is fully implemented and then I&M will subsume some of these activities such as feeder hardening.

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5.1 Performance Targets

The performance of this strategy will be measured by:

- Maintaining the inspection cycle
- Replacing assets in accordance with the priority codes and associated replacement time frames as adjusted in the long term compliance plan
- Meeting all state specific regulatory requirements for reliable service to customers

6.0 Risk Assessment

Individual assets have a minimal risk in any of the categories listed below. Collectively deteriorated equipment related interruptions are one of the main drivers of an unreliable system.

6.1 Safety & Environmental

Inspection and Maintenance identifies potential environmental and safety problems (e.g. oil leaks damaged equipment and elevated voltage). Failure to implement this strategy, and identify and correct these potential problems may lead to an increased risk of injury to employees or to the public and may create undesirable environmental damage.

6.2 Reliability

Lack of proactive replacement of marginal equipment as part of a cyclical inspection program will have a negative impact on reliability. The overall impact to reliability will increase over time as the quantity of marginal equipment increases. This risk is difficult to measure, due to the trend of deteriorated equipment.

6.3 Customer/Regulatory/Reputation

Implementation of this strategy will impact positively our customers due to improvement in reliability performance, and a reduction in hazards due to elevated voltage on publicly accessible facilities. In several states, National Grid has regulatory requirements prescribing cyclical inspection programs and associated repair timeframes based on the severity of the problem. The Inspection Program meets or exceeds these regulatory requirements. Failing to inspect and repair or replace assets would result in noncompliance with our regulatory requirement. Refer to the state specific section in the Appendix of the strategy.

7.0 Data Requirements

7.1 Existing/Interim:

Smallworld/ArcSDE – feeder assets
Computapole – inspection data

7.2 Proposed:

Same

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8.0 References

- EOP D004 – Distribution Line Patrol and Maintenance
- EOP UG006 – Underground Inspection and Maintenance
- EOP T007 – Transmission Line Patrol 23kV – 345kV
- EOP G016 – Elevated Equipment Voltage Testing
- EOP G017 – Street Light Standard Inspection Program
- NY PSC Order 04-M-0159
- Massachusetts DTE Directive 12/9/05
- Feeder Hardening Strategy (Approved July, 2, 2008)

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9.0 Appendix A

Definitions:

Elevated Equipment Voltage Test: An A.C. rms voltage difference between utility equipment and the earth, or to nearby grounded facilities that exceeds the highest perceptible voltage levels for humans.

Infrared Inspection: An inspection conducted to detect abnormal heating conditions associated with separable connectors. An infrared inspection is required before work begins in an enclosed space, enclosure, pad mounted transformer or pad mounted switchgear.

Patrol: An assessment of National Grid facilities for the purpose of determining the condition of the facility and any associated components.

Aerial Infrared: Helicopter based thermographic imaging of connections and equipment.

Aerial Patrols: Helicopter based visual examination of subtransmission and transmission facilities and equipment.

Fast Feeder Patrols: An assessment to identify and fix immediate problems likely to cause an outage on overhead distribution feeder main line construction from the substation breaker to fused 3 phase side taps ($\geq 65K$ fuse). Additional distribution feeders at voltages as high as 34.5kV that supply large number of customers may be identified as part of the Fast Feeder Patrol. The goal of the program is outage prevention.

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10.0 Appendix B

New York Specific

The New York Public Service Commission (PSC) requires the following:

1. Annual stray voltage testing shall be conducted on all utility facilities that are capable of conducting electricity and are publicly accessible including municipal-owned streetlights. Elevated voltage testing shall be performed based on 1 volt standard set by the PSC.
2. Inspection program on a five-year cycle that shall include, at a minimum, visual examination of towers, poles, guy wires, risers, overhead cables and conductors, transformers, breakers, switches, other aboveground equipment and facilities, the interior of manholes, service boxes, vaults, and other underground structures.
3. A quality assurance program to ensure timely and proper compliance with safety standards.

	Required By	
	Regulatory	Strategy
Overhead Distribution		
Five-year cycle distribution overhead inspection	✓	✓
Five-year cycle infrared inspection on overhead mainline		✓
Underground		
Five-year cycle underground inspection	✓	✓
Five-year cycle infrared Inspection of all separable components		✓
Five-year cycle underground transformers and switchgear internal inspection	✓	✓
Sub-transmission		
Five-year cycle ground base patrol inspection	✓	✓
Three-year cycle Aerial Helicopter infrared Patrol		✓
Annual Aerial helicopter patrol		✓
Other Inspections		
Elevated voltage testing ¹	✓	✓
Five-year cycle inspection on Street Lights	✓	✓
Annual inspection of Capacitors and Regulators		✓
Semi Annual inspection on Reclosers		✓
Semi Annual fast feeder patrol		✓

Table 2: NY Regulatory vs. Strategy Inspection Requirements

1- Per New York PSC, elevated voltage testing shall be performed annually.

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11.0 Appendix C

Massachusetts Specific

The Massachusetts Department of Public Utilities (DPU) requires the following:

1. 20% of facilities shall be tested for elevated voltage annually on five years rolling basis. This include at minimum to inspect and test the following equipment where accessible by the general public:
 - Metallic street lights and fixtures
 - Metallic risers, sweeps and conduits
 - Manhole and handhole covers
 - Secondary pedestals
 - Pad mount transformers and translosures
 - Pad mount switchgear, termination cabinets and junction boxes
 - Control cabinets such as pole mounted capacitor controls
2. Inspect all manholes over a 5-year cycle, and create a database of manhole conditions and required repairs.

	Required By	
	Regulatory	Strategy
Overhead Distribution		
Five-year cycle distribution overhead inspection		✓
Five-year cycle infrared inspection on overhead mainline		✓
Underground		
Five-year cycle underground inspection ¹	✓	✓
Five-year cycle infrared Inspection of all separable components		✓
Five-year cycle underground transformers and switchgear internal inspection		✓
Sub-transmission		
Five-year cycle ground base patrol inspection		✓
Three-year cycle Aerial Helicopter infrared Patrol		✓
Annual Aerial helicopter visual patrol		✓
Other Inspections		
Elevated voltage testing ²	✓	✓
Five-year cycle inspection on Street Lights		✓
Annual inspection of Capacitors and Regulators		✓
Semi Annual inspection on Reclosers		✓
Semi Annual fast feeder patrol		✓

Table 3: MA Regulatory vs. Strategy Inspection Requirements

1- Massachusetts DPU requires inspection on manholes only

2- For Massachusetts, elevated voltage testing shall be performed on a five-year cycle (20% annually)

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Inspection and Maintenance Strategy
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12.0 Appendix D

Rhode Island Specific

There are no specific regulatory inspection requirements for Rhode Island.

	Required By	
	Regulatory	Strategy
Overhead Distribution		
Five-year cycle distribution overhead inspection		✓
Five-year cycle infrared inspection on overhead mainline		✓
Underground		
Five-year cycle underground inspection		✓
Five-year cycle infrared Inspection of all separable components		✓
Five-year cycle underground transformers and switchgear internal inspection		✓
Sub-transmission		
Five-year cycle ground base patrol inspection		✓
Three-year cycle Aerial Helicopter infrared Patrol		✓
Annual Aerial helicopter visual patrol		✓
Other Inspections		
Elevated voltage testing		✓
Five-year cycle inspection on Street Lights		✓
Annual inspection of Capacitors and Regulators		✓
Semi Annual inspection on Reclosers		✓
Semi Annual fast feeder patrol		✓

Table 4: RI Regulatory vs. Strategy Inspection Requirements

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13.0 Appendix E

New Hampshire Specific

There are no specific regulatory inspection requirements for New Hampshire.

	Required By	
	Regulatory	Strategy
Overhead Distribution		
Five-year cycle distribution overhead inspection		✓
Five-year cycle infrared inspection on overhead mainline		✓
Underground		
Five-year cycle underground inspection		✓
Five-year cycle infrared Inspection of all separable components		✓
Five-year cycle underground transformers and switchgear internal inspection		✓
Sub-transmission		
Five-year cycle ground base patrol inspection		✓
Three-year cycle Aerial Helicopter infrared Patrol		✓
Annual Aerial helicopter visual patrol		✓
Other Inspections		
Elevated voltage testing		✓
Five-year cycle inspection on Street Lights		✓
Annual inspection of Capacitors and Regulators		✓
Semi Annual inspection on Reclosers		✓
Semi Annual fast feeder patrol		✓

Table 5: NH Regulatory vs. Strategy Inspection Requirements

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14.0 Appendix F

	Responsibilities	Operations				Inspection Group			
		Incremental Cost		Incremental FTEs		Incremental Cost		Incremental FTEs	
		NE	NY	FTEs-NE	FTEs-NY	NE	NY	FTEs-NE	FTEs-NY
Overhead Distribution									
Five-year cycle distribution overhead inspection	Inspection					\$0	\$0		
Five-year cycle infrared inspection on overhead mainline ¹	Inspection					\$75,000	\$125,000		
Sub-transmission									
Five-year cycle ground base patrol inspection	Inspection					\$224,000	\$0	2	
Three-year cycle Aerial Helicopter infrared Patrol ¹	Inspection					\$32,000	\$96,000		
Annual Aerial helicopter patrol ¹	Inspection					\$70,000	\$210,000		
Underground									
Five-year cycle Manhole inspection including infrared	Operations	\$0	\$0	0	0	\$0	\$0		
Five-year cycle Vaults inspection including infrared	Operations	\$0	\$0	0	0	\$0	\$0		
Five-year cycle Metallic Handhold inspection	Inspection					\$112,000	\$0	1	
Metallic Handholds Infrared Inspection	Inspection					\$112,000	\$112,000	1	1
Five-year cycle Padmounted transformers -Live Front & Switch Gears	Operations	\$336,000	\$1,344,000	3	12	\$0	\$0		
Live Front Transformers & Switchgears Infrared Inspection	Operations					\$0	\$0		
Five-year cycle Padmounted transformers - Dead Front	Inspection					\$672,000	\$0	6	
Dead front Padmounted Transformers Infrared Inspection	Inspection					\$224,000	\$224,000	2	2
Other Inspections									
Elevated Voltage (EV) testing	Inspection					\$34,000	\$0		
Five-year cycle inspection on Street Lights	Inspection					\$34,000	\$0		
Annual inspection of Capacitors and Regulators	Operations	\$0	\$672,000	0	6	\$0	\$0		
Semi Annual inspection on Reclosers	Operations	\$0	\$0			\$0	\$0		
Semi Annual Fast Feeder Patrol	Inspection					\$276,884	\$204,706	2	2
Additional Resources									
Coordinators/ Program Mangers FTE	Inspection					\$149,000	\$149,000	1	1
QA/QC Recommendations	Performance Mgmt					\$648,000	\$1,215,000	8	15
Total (includes direct labor costs only - Loaded)		\$336,000	\$2,016,000	3	18	\$2,662,884	\$2,335,706	23	21
Total Vehicle, Equip, Tools, Other		\$81,000	\$486,000			\$229,500	\$85,000		
Total Implementation Costs by State		\$417,000	\$2,502,000			\$2,892,384	\$2,420,706		
Total Implementation Costs - NY & NE		\$2,919,000			21	\$5,313,090			44

¹ These costs are currently budgeted within operation and might require transfer to the inspection group.

Table 6: Annual Incremental Inspections Resources/Costs

Uncontrolled when printed

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15.0 Appendix G

Below are approximate estimates for a 7 years plan for the total resulting work based on the inspection program and the incremental staff to support the implementation of the strategy.

			FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17		
Overhead Distribution	MA	CAPEX	\$1,389,276	\$15,086,313	\$29,246,442	\$33,812,121	\$37,914,708	\$32,237,608	\$16,714,299	\$5,756,670		
		OPEX related to CAPEX	\$168,862	\$1,593,354	\$3,074,133	\$3,548,964	\$3,967,507	\$3,380,102	\$1,955,610	\$887,241		
		O&M	\$1,082,254	\$3,349,706	\$5,977,910	\$6,733,728	\$7,128,794	\$5,651,474	\$3,384,021	\$1,872,386		
		REMOVAL	\$138,928	\$1,508,631	\$2,924,644	\$3,381,212	\$3,791,471	\$3,223,761	\$1,671,430	\$575,667		
	RI	CAPEX	\$523,495	\$5,684,698	\$11,020,398	\$12,740,799	\$14,286,702	\$12,147,504	\$6,298,142	\$2,169,180		
		OPEX related to CAPEX	\$63,629	\$600,394	\$1,158,369	\$1,337,291	\$1,495,003	\$1,273,662	\$736,896	\$334,323		
		O&M	\$407,806	\$1,262,208	\$2,252,546	\$2,537,347	\$2,686,212	\$2,129,541	\$1,275,138	\$705,537		
		REMOVAL	\$52,350	\$568,470	\$1,102,040	\$1,274,080	\$1,428,670	\$1,214,750	\$629,814	\$216,918		
	NH	CAPEX	\$100,672	\$1,093,211	\$2,119,307	\$2,450,154	\$2,747,443	\$2,336,059	\$1,211,181	\$417,150		
		OPEX related to CAPEX	\$12,236	\$115,460	\$222,763	\$257,171	\$287,501	\$244,935	\$141,711	\$64,293		
		O&M	\$78,424	\$242,732	\$433,182	\$487,951	\$516,579	\$409,527	\$245,219	\$135,680		
		REMOVAL	\$10,067	\$109,321	\$211,931	\$245,015	\$274,744	\$233,606	\$121,118	\$41,715		
	NY	CAPEX	\$10,003,800	\$19,075,600	\$22,304,600	\$22,576,000	\$19,556,600	\$17,543,500	\$15,969,300	\$11,878,100		
		OPEX related to CAPEX	\$1,839,150	\$3,619,920	\$4,291,170	\$4,416,600	\$4,543,200	\$4,725,810	\$4,625,790	\$3,154,680		
		O&M	\$4,535,550	\$8,746,480	\$10,288,730	\$10,527,400	\$8,399,700	\$6,744,440	\$6,062,160	\$4,759,220		
		REMOVAL	\$1,000,380	\$1,907,560	\$2,230,460	\$2,257,600	\$1,955,660	\$1,754,350	\$1,596,930	\$1,187,810		
Subtransmission	NE	Budget is included as part of the above overhead distribution estimates in NE States										
	NY	CAPEX	\$7,600,000	\$9,600,000	\$9,600,000	\$9,600,000	\$9,600,000	\$2,400,000	\$2,400,000	\$2,400,000		
		OPEX related to CAPEX	\$350,000	\$1,000,000	\$1,000,000	\$1,000,000	\$1,000,000	\$250,000	\$250,000	\$250,000		
		Ops O&M	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
Underground	MA	REMOVAL	\$760,000	\$960,000	\$960,000	\$960,000	\$960,000	\$240,000	\$240,000	\$240,000		
		CAPEX	\$950,000	\$950,000	\$950,000	\$950,000	\$950,000	\$950,000	\$950,000	\$950,000		
		OPEX related to CAPEX	\$283,000	\$283,000	\$283,000	\$283,000	\$283,000	\$283,000	\$283,000	\$283,000		
		REMOVAL	\$95,000	\$95,000	\$95,000	\$95,000	\$95,000	\$95,000	\$95,000	\$95,000		
	RI	CAPEX	\$300,000	\$300,000	\$300,000	\$300,000	\$300,000	\$300,000	\$300,000	\$300,000		
		OPEX related to CAPEX	\$28,000	\$28,000	\$28,000	\$28,000	\$28,000	\$28,000	\$28,000	\$28,000		
		REMOVAL	\$30,000	\$30,000	\$30,000	\$30,000	\$30,000	\$30,000	\$30,000	\$30,000		
		CAPEX	\$100,000	\$100,000	\$100,000	\$100,000	\$100,000	\$100,000	\$100,000	\$100,000		
	NH	OPEX related to CAPEX	\$9,000	\$9,000	\$9,000	\$9,000	\$9,000	\$9,000	\$9,000	\$9,000		
		REMOVAL	\$10,000	\$10,000	\$10,000	\$10,000	\$10,000	\$10,000	\$10,000	\$10,000		
		CAPEX	\$2,500,000	\$2,500,000	\$2,500,000	\$2,500,000	\$2,500,000	\$2,500,000	\$2,500,000	\$2,500,000		
		OPEX related to CAPEX	\$300,000	\$300,000	\$300,000	\$300,000	\$300,000	\$300,000	\$300,000	\$300,000		
	NY	O&M	\$610,000	\$832,500	\$880,000	\$880,000	\$880,000	\$880,000	\$880,000	\$880,000		
		REMOVAL	\$250,000	\$250,000	\$250,000	\$250,000	\$250,000	\$250,000	\$250,000	\$250,000		
		Fast Feeder Patrol	MA	CAPEX	\$461,599	\$461,599	\$461,599	\$461,599	\$461,599	\$461,599	\$461,599	\$461,599
				OPEX related to CAPEX	\$46,160	\$46,160	\$46,160	\$46,160	\$46,160	\$46,160	\$46,160	\$46,160
O&M	\$71,015			\$71,015	\$71,015	\$71,015	\$71,015	\$71,015	\$71,015	\$71,015		
REMOVAL	\$46,160			\$46,160	\$46,160	\$46,160	\$46,160	\$46,160	\$46,160	\$46,160		
RI	CAPEX	\$162,765	\$162,765	\$162,765	\$162,765	\$162,765	\$162,765	\$162,765	\$162,765			
	OPEX related to CAPEX	\$16,277	\$16,277	\$16,277	\$16,277	\$16,277	\$16,277	\$16,277	\$16,277			
	O&M	\$25,041	\$25,041	\$25,041	\$25,041	\$25,041	\$25,041	\$25,041	\$25,041			
	REMOVAL	\$16,277	\$16,277	\$16,277	\$16,277	\$16,277	\$16,277	\$16,277	\$16,277			
NH	CAPEX	\$25,636	\$25,636	\$25,636	\$25,636	\$25,636	\$25,636	\$25,636	\$25,636			
	OPEX related to CAPEX	\$2,564	\$2,564	\$2,564	\$2,564	\$2,564	\$2,564	\$2,564	\$2,564			
	O&M	\$3,944	\$3,944	\$3,944	\$3,944	\$3,944	\$3,944	\$3,944	\$3,944			
	REMOVAL	\$2,564	\$2,564	\$2,564	\$2,564	\$2,564	\$2,564	\$2,564	\$2,564			
NY	CAPEX	\$975,000	\$975,000	\$975,000	\$975,000	\$975,000	\$975,000	\$975,000	\$975,000			
	OPEX related to CAPEX	\$97,500	\$97,500	\$97,500	\$97,500	\$97,500	\$97,500	\$97,500	\$97,500			
	O&M	\$150,000	\$150,000	\$150,000	\$150,000	\$150,000	\$150,000	\$150,000	\$150,000			
	REMOVAL	\$97,500	\$97,500	\$97,500	\$97,500	\$97,500	\$97,500	\$97,500	\$97,500			
Inspection cost	NE	Inspection	\$2,892,384	\$2,892,384	\$2,892,384	\$2,892,384	\$2,892,384	\$2,892,384	\$2,892,384	\$2,892,384		
		Operations	\$417,000	\$417,000	\$417,000	\$417,000	\$417,000	\$417,000	\$417,000	\$417,000		
	NY	Inspection	\$2,420,706	\$2,420,706	\$2,420,706	\$2,420,706	\$2,420,706	\$2,420,706	\$2,420,706	\$2,420,706		
		Operations	\$2,502,000	\$2,502,000	\$2,502,000	\$2,502,000	\$2,502,000	\$2,502,000	\$2,502,000	\$2,502,000		
Total	CAPEX		\$25,092,244	\$56,014,822	\$79,765,748	\$86,654,074	\$89,580,452	\$72,139,671	\$48,067,922	\$28,096,100		
	OPEX related to CAPEX		\$3,216,378	\$7,711,629	\$10,528,936	\$11,342,526	\$12,075,710	\$10,657,008	\$8,492,507	\$5,473,037		
	O&M		\$6,964,034	\$14,683,627	\$20,082,368	\$21,416,426	\$19,861,286	\$16,064,982	\$12,096,539	\$8,602,823		
	REMOVAL		\$2,509,224	\$5,601,482	\$7,976,575	\$8,665,407	\$8,958,045	\$7,213,967	\$4,806,792	\$2,809,610		
	Inspection		\$8,232,090	\$8,232,090	\$8,232,090	\$8,232,090	\$8,232,090	\$8,232,090	\$8,232,090	\$8,232,090		
System Total			\$46,013,970	\$92,243,650	\$126,585,717	\$136,310,523	\$138,707,583	\$114,307,718	\$81,695,851	\$53,213,660		

Table 7: Long Term Budget for Inspection Program

Rebuttal Testimony of
Rudolph L. Wynter

REBUTTAL TESTIMONY

OF

RUDOLPH L. WYNTER, JR.

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I. INTRODUCTION AND PURPOSE OF TESTIMONY 1

**II. LINKAGE BETWEEN COMMODITY COSTS AND UNCOLLECTIBLE
EXPENSE 2**

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1 **I. INTRODUCTION AND PURPOSE OF TESTIMONY**

2 **Q. Please state your full name and business address.**

3 A. My name is Rudolph L. Wynter, Jr. My business address is One MetroTech Center,
4 Brooklyn, New York 11201.

5
6 **Q. Did you previously submit pre-filed testimony in this proceeding?**

7 A. Yes. I submitted pre-filed direct testimony on June 1, 2009.

8
9 **Q. What is the purpose of your rebuttal testimony?**

10 A. My testimony responds to the Direct Testimony of Mr. Bruce A. Gay, which was
11 submitted in this proceeding on behalf of the Rhode Island Division of Public Utilities
12 and Carriers (the “Division”). Specifically, I will provide comments regarding Mr. Gay’s
13 claims regarding (1) the linkage between increasing commodity costs and uncollectible
14 accounts and (2) a deviation from the ratemaking practice used by the Rhode Island
15 Public Utilities Commission (the “Commission”) to establish the write- off ratio used to
16 calculate uncollectible expense for both distribution and commodity-related recovery in
17 this case. In the end, the Company recommends that the Commission maintain its
18 established policy of setting rates using the Company’s actual historical ratio of annual
19 write-offs.

II. LINKAGE BETWEEN COMMODITY COSTS AND UNCOLLECTIBLE
EXPENSE

Q. How would you summarize the Division's testimony concerning the connection between commodity costs and the uncollectible account experience?

A. Mr. Gay dismisses the proposition that charge-off levels in recent years (including the test year ending December 31, 2008) are substantially attributable to external forces, namely, relatively high supply costs and other factors not within the control of the Company, including the historic economic decline that Rhode Island and the rest of the nation is experiencing. Instead Mr. Gay assigns responsibility for the rate of write-offs to his perception that the Company has not been aggressive enough in its management of overdue accounts receivable by failing to increase customer shut-offs in order to collect arrearage balances.

Q. Do you agree with the Division's overall premise?

A. No, I do not. Although the Company would agree that electric supply rates are not the sole driver of increased write-off levels, the Company disagrees that it has not appropriately managed customer arrearage balances or that it should be shutting off customers based on an inflexible, uniformly applied cutoff timeframe.

Q. What is the Division's specific claim with respect to the relationship between recent sharp increases in commodity prices and recent increases in uncollectible write-offs?

1 A. Mr. Gay states in his testimony that “it does not appear that recent increases in
2 commodity prices are the primary factor in uncollectible expense” (Gay Direct
3 Testimony at 7, 11-13). Elsewhere in his testimony Mr. Gay acknowledges that “it is
4 difficult to determine the exact correlation between commodity prices, average monthly
5 bill increases and subsequent customer defaults” (*id.* at 9, 11-13). However, Mr. Gay’s
6 testimony leaves the impression that he disagrees that there is a significant or direct
7 relationship between the dramatic increases in commodity prices that have occurred in
8 the past two years and the increased inability of customers to pay their electric bills.

9
10 **Q. How do you respond to Mr. Gay’s position that increases in commodity prices have**
11 **little impact on a customer’s monthly bill?**

12 A. As an initial matter, I would note that Mr. Gay relies on the fact that external factors
13 *other than commodity prices* contribute to the increased level of uncollectible write-offs
14 experienced by the Company in support of his claim that commodity prices are not a
15 significant driver of uncollectible write-offs. However, the fact that external factors other
16 than commodity prices have a bearing on revenue collections *in addition to* the impact of
17 rising commodity prices serves only to underscore the fact that there are many moving
18 parts within the customer consumption, billing and collections dynamic that (1) are
19 beyond the control of the Company, and (2) make it difficult to isolate cause and effect in
20 terms of evaluating write-off experience from period to period. From the Company’s
21 perspective, this is the reason that the Commission’s practice has been to use an average

1 of the actual annual write-off rate over a multi-year period to identify the appropriate
2 uncollectible ratio in setting rates.

3
4 For example, in addition to electric commodity prices, the recovery of electric service
5 revenues is a function of many factors including natural gas commodity prices, gasoline
6 prices, health-care prices, global, national and local economic conditions, availability of
7 energy assistance funding and prevailing regulatory requirements, with the relative
8 weighting of these factors entirely uncertain. The Company acknowledged in its direct
9 case that these factors affect its write-off experience (Direct Testimony of Rudy L.
10 Wynter at 4-5). However, the fact remains that commodity cost recovery represents a
11 significant portion of the customer bill, and therefore, increasing commodity prices have
12 the most direct effect on the level of customer defaults experienced by the Company (see
13 Schedule NG-RLW-2).

14
15 Secondly, Mr. Gay provides two charts comparing changes in Standard Offer rates to the
16 average customer bill amount during the period January 2007 through June 2009. Mr.
17 Gay selects different 12-month points along the “average monthly bill” lines in his two
18 attachments to show how the monthly average bill either increased or declined as
19 compared to Standard Offer rates. Yet, he also acknowledges that other factors could
20 explain variations in write-offs when he says that “other factors must explain some of the
21 variation, including seasonality, energy usage, energy conservation (especially by non-
22 residential customers in a recession), weather and economic conditions” (Gay Direct

1 Testimony at.8, 14-16). It is exactly because of the interplay of these other factors that
2 Mr. Gay's assertion that commodity costs have had little correlation to net write-offs
3 simply cannot be proven by his comparing Standard Offer pricing levels with the average
4 customer bill.

5
6 Instead, the charts appear to lead to two conclusions: (1) the average customer's electric
7 bill fluctuates during the course of the year for the time periods that are depicted,
8 reaching its lowest point in May, and (2) an increase in Standard Offer rates accompanies
9 an increase in the average customer bill. These conclusions support the Company's
10 experience that increasing commodity rates significantly affects the ability of customers
11 to pay their bills. Mr. Gay has isolated time points in May 2007, 2008 and 2009, which,
12 as I noted above, are the recurring low points of the customer average bill for the year.
13 Mr. Gay is, in effect, limiting his focus to specific points in time when, as his chart
14 shows, there were no Standard Offer price increases and when the average customer bill
15 is at its low point for the year. His analysis ignores the fact demonstrated in his chart,
16 which is that when commodity rates increases did occur at other points during those
17 years, the customer's average bill also increased. Rather than focus on the time points
18 chosen by Mr. Gay, it is much more instructive to note the relationship between the
19 Standard Offer rate increases that occurred in January 2008, July-August 2009 and
20 December-January 2009 and the average customer bill increases that occurred at those
21 time points. When focusing on those points in time, it is apparent that increases in
22 Standard Offer rates do correlate with concurrent increases in the average customer bill.

Moreover, Mr. Gay has not put forth a price-volume analysis as a way of defending his position. Because of this, Mr. Gay cannot claim that commodity rates have had little effect upon net write-offs. If commodity rates were lower over time, the trending of average monthly bills in Mr. Gay's Attachment 1 and Attachment 2 would have been lower on each of those graphs.

The impact of the ongoing recession on future write-offs is also no small matter. The unemployment rate in the state of Rhode Island is increasing and is not fully reflected in the Company's historical uncollectible ratios. The following graph is taken from the website of the United States Department of Labor's Bureau of Labor Statistics. This illustrates the seasonally adjusted unemployment rate for Rhode Island through August 2009. The last point depicts an August 2009 preliminary unemployment rate of 12.8 percent.



1 As a result, the Division is advocating for the setting of rates to include a level of
2 uncollectible expense, which is artificially low because of the approach Mr. Gay has
3 taken, as well as practically out-of-step with the external factors that influence the
4 collection rate.

5
6 Moreover, a strong statement can be made concerning the influence competing energy
7 costs (such as gas supply outlays facing home heating customers) may have had on the
8 historical levels of net write-off in recent years. This is particularly true in Rhode Island
9 where the Company services many of the same home heating customers that it does for
10 electric. Customers struggling with high winter bills will quite often choose to keep the
11 heat on while ignoring their electric bill. In many cases (as has occurred in the
12 Company's Upstate New York service territory), customers will give up on their home
13 energy payments (both electric and gas) if their winter bills become unmanageable.

14
15 Schedule NG-RLW-R-1 represents the historic gas supply costs for National Grid's
16 Rhode Island gas residential and small commercial customers for the winter months of
17 November 2008 through March 2009. The commodity rates faced by National Grid's gas
18 customers reached unprecedented levels nearly four years ago. Exacerbating the
19 quandary faced by dual-service customers is the winter moratorium period on
20 terminations. This situation continues to feed the arrears that began to accumulate during
21 the winter months for both the Company's electric and gas customers.

1 **Q. Does the Division adequately prove its argument that electric commodity rates are**
2 **not a principal cause of elevated write-off totals?**

3 A. Although the analysis offered by Mr. Gay is commendable in terms of encompassing an
4 analytical approach, the Company believes that the Division's own examples and
5 arguments are supportive of the Company's case.
6

7 **III. SERVICE TERMINATIONS**

8 **Q. After discounting soaring commodity rates and the declining economy as primary**
9 **drivers of the Company's charge-offs, Mr. Gay suggests that the test year write-off**
10 **rate would have been dramatically reduced "[h]ad the company accelerated its**
11 **disconnection activity on the entire portfolio of delinquent accounts in 2007." How**
12 **do you respond to this contention?**

13 A. There are three points that I would like to make regarding Mr. Gay's analysis. First, Mr.
14 Gay's contention ignores the fact that, since 2004, the Company's disconnection
15 activities have dramatically increased year-over-year, doubling in the period 2004
16 through 2008. For example, as shown in the Company's Docket 1725 Report regarding
17 residential accounts, the Company performed 10,015 disconnections in 2004. During that
18 year, the Company's charge-off rate was 0.72 percent (Schedule NG-RLW-1). By
19 comparison, the Company performed 20,721 disconnections in 2008, which is twice as
20 many disconnections as performed in 2004. Nevertheless, the Company's charge-off rate
21 in 2008 was 1.08 percent. As a result, it is clear that Mr. Gay's emphasis on a correlation

1 between disconnections and reduction in write-offs does not account for the fact that
2 there are factors beyond the Company's control that affect the write-off rate.
3

4 **Q. Mr. Gay suggests that decreasing the bad debt amount can be accomplished by**
5 **simply increasing the disconnection rate. Do you agree that the Commission should**
6 **establish bad-debt recovery on the premise that all residential customers would be**
7 **terminated after 150 days and all non-residential customers would be terminated**
8 **after 90 days?**

9 A. No. I do not. Mr. Gay's recommendation does not correspond with the realities of
10 serving Rhode Island customers. Each customer is experiencing their own circumstances
11 and the Company has an obligation to work with customers and to show a level of
12 flexibility in dealing with their specific circumstances. There is a cost imposed on the
13 system to disconnect and restore service, as well as the substantial hardship for customers
14 in experiencing the service termination. There are also very difficult, customer-specific
15 decisions that the Company must make in evaluating service terminations. For example,
16 when a small C&I customer is terminated, the revenue stream available to pay the past
17 due arrearages is lost, which is counterproductive unless all other efforts to collect the
18 arrearage amount are exhausted. As a result, the Company uses service terminations as a
19 collection tool, but does not apply this tool if there is a way to work revenue recovery
20 issues out with the customer.
21

1 Moreover, in addition to the financial challenges to customers that result in uncollectible
2 utility bills, there are statutory and regulatory protections that exist to protect our
3 customers from service termination. The Commission rules protect against residential
4 service terminations during the winter moratorium, which is the six month period
5 between November 1 and April 15. Through its rules, the Commission attempts to
6 protect from termination during those winter months residential customers and
7 particularly those most exposed to utility service termination such as low income, senior
8 citizens, and medically challenged. Since 2008, the Company is, by statute, also
9 prohibited from disconnecting service to households where there is a child under the age
10 of 2 years. Similarly, Commission rules prohibit the Company from disconnecting
11 service to a household where there is a handicapped person or a person over 65 years of
12 age without obtaining Division approval. Moreover, a customer has the right under
13 Commission rules to request an informal hearing and then a formal hearing with the
14 Division.¹ A customer's service may not be terminated during the pendency of that
15 process. When the Company has made the necessary customer notices and the hearing
16 process has run its course, Company crews sent to terminate service may not be able to
17 gain access to customer meters in order to effectuate termination. Even at the time a
18 Company crew has arrived to implement a disconnection, customers have the ability to
19 claim medical or other protected status and prevent the service termination.
20

¹ A customer may also appeal any decision of the Division to Superior Court, where the customer may seek a stay of a disconnection order.

1 **Q. Does the Company believe it has made reasonable efforts to control its arrears and**
2 **accounts receivable levels?**

3 A. Yes. As I described above, the process of controlling arrearage growth and accounts
4 receivable is not as simple as Mr. Gay implies in his testimony, especially given the
5 regulatory environment and the other external forces that impact that process. In
6 response to the increased arrearages and write-off levels influenced by these forces, the
7 Company implemented its bad debt mitigation strategy after the first quarter of calendar
8 year 2008. This strategy was described in response to Division Data Request 10-13.
9 This strategy employs increased outbound calls and field collection activities. Within my
10 pre-filed testimony, Schedule NG-RLW-4, I have detailed the incremental credit and
11 collections costs sought in the revenue requirement as a result of these activities. The
12 Company disagrees with the Division's assertion that funding for the bad debt mitigation
13 strategy is not warranted. It ignores the probability that bad debt write-offs *would have*
14 *been significantly greater in the test year* had the Company *not* engaged in these
15 activities

16
17 Furthermore, with respect to service terminations there are competing public policy
18 objectives at play. Although the Company believes that balancing legitimate concerns
19 for customers confronted with service termination against the need to pursue collection of
20 overdue accounts can ultimately lead to the best result for customers and the Company,
21 the balancing of those interests can also hinder collection activities and increase write-off
22 rates.

1 **Q. Do you agree with the recommended uncollectible rate of 0.71% supported by Mr.**
2 **Gay?**

3 A. No. Mr. Gay's suggested reduction to the Company's proposed write-off rate is based on
4 adjustments to actual, average level of uncollectible write-offs and is unreasonable.
5 Putting all else aside, the calculation assumes that, had the Company uniformly turned off
6 residential customers with arrearage balances after 150 days and commercial and
7 industrial customers with arrearage balances after 90 days, *the Company would have*
8 *collected 100 percent of the arrearage balances.* There is no basis for this conclusion.

9 Second, Mr. Gay's suggested reduction implies that the Company should be applying an
10 inflexible, uniform cutoff threshold without regard to customer-specific circumstances –
11 and that if it does allow customers flexibility, it will be penalized through the bad debt
12 recovery amount.

13
14 Lastly, Mr. Gay fundamentally assumes that the bad debt level experienced during the
15 test year resulted from the Company's mismanagement of its portfolio of overdue
16 accounts and not from the other real factors impacting customers' ability to pay their
17 bills, such as the steep economic decline and high commodity rates. His proposal
18 assumes that the Company could have reduced charge-off levels experienced in 2008 by
19 resorting to draconian shut-off activity while ignoring the fact that the Company's 2008
20 shut-off activity was already double what it was just four years before. The Company has
21 demonstrated that there are many external factors that influence write-offs, causes that
22 Mr. Gay admits exist. Given the trend in the Rhode Island seasonally-adjusted

1 unemployment rate shown above together with the other external factors that
2 significantly impact the Company's collection activities, the Company believes that the
3 uncollectible rate experienced during the test year will persist into the near future.

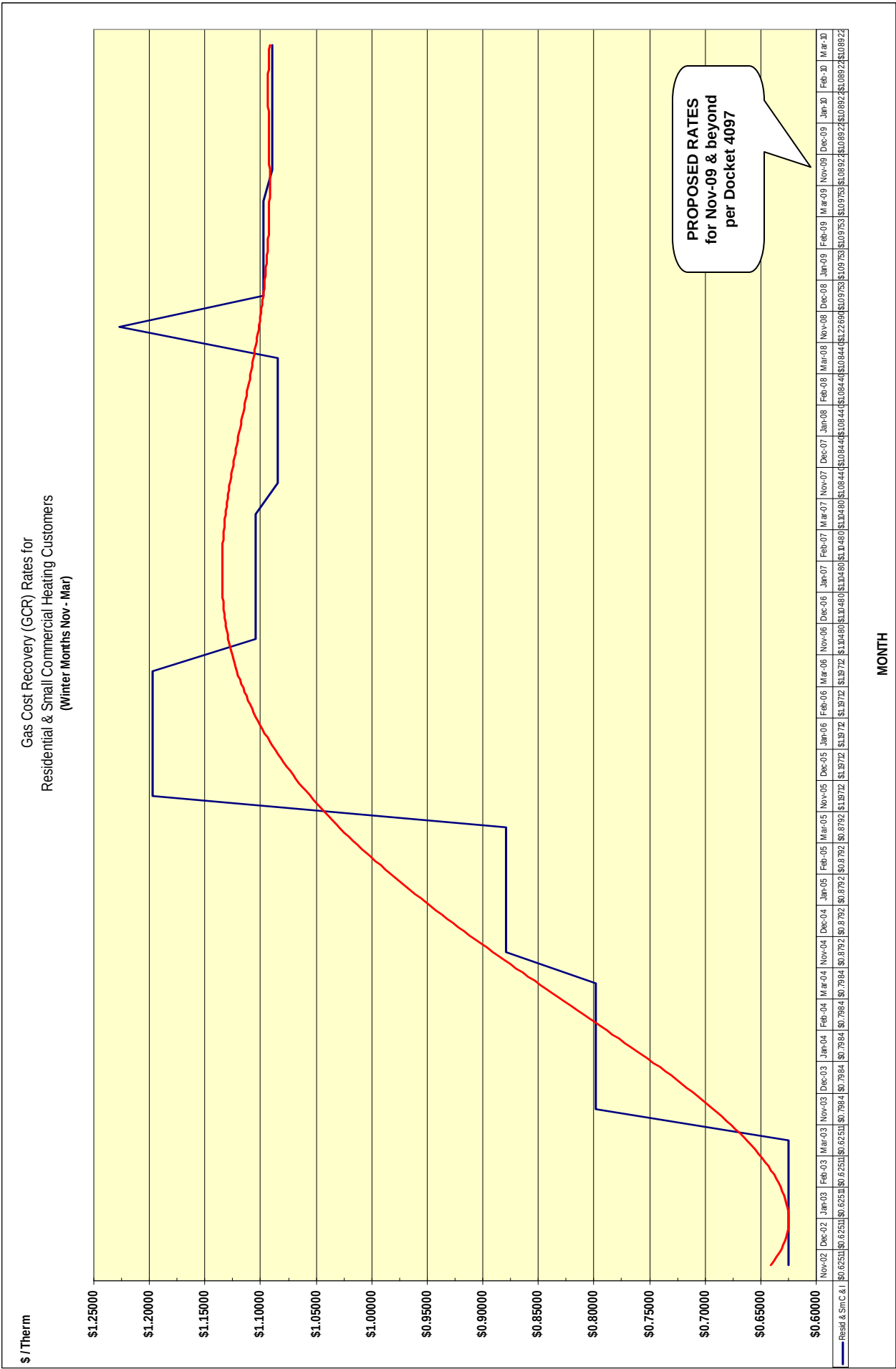
4

5 **Q. Does that conclude your testimony?**

6 **A. Yes. It does.**

Schedule NG-RLW-R-1

National Grid Gas Supply Costs in Rhode Island



THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
Docket No. R.I. P.U.C. 4065
Rebuttal Witness: Tierney

PRE-FILED REBUTTAL TESTIMONY

OF

SUSAN F. TIERNEY, Ph.D.

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I. Introduction

Q. Please state your full name.

A. My name is Susan F. Tierney.

Q. Did you previously submit pre-filed direct testimony in this proceeding?

A. Yes. I submitted pre-filed direct testimony on June 1, 2009.

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

A. I have been asked by National Grid's Narragansett Electric Company (the "Company") to provide rebuttal testimony in response to various points made by several witnesses who testified on behalf of other parties in this proceeding. My rebuttal testimony addresses topics raised by these witnesses with respect to the overall structure and elements of the Company's proposed Revenue Decoupling Ratemaking Plan ("RDR Plan") and its revenue decoupling mechanism ("RDM").

Q. Please identify the witnesses to whom you are responding in this rebuttal testimony.

A. I am responding to the testimony of: John Farley (on behalf of The Energy Council of Rhode Island ("TEC-RI")) and Bruce Oliver (for The Division of Public Utilities and Carriers ("Division")). I also refer briefly to comments of several other witnesses: Ms. Shannon Cleveland (witness for the Conservation Law Foundation ("CLF")); Dr. Mark N. Lowry (witness for the Rhode Island Energy Efficiency and Resource Management Council ("RI EERMC")); and Mr. Matt Kahal (witness for the Division).

Q. Please explain how your testimony is organized.

A. My rebuttal testimony covers the following topics:

- In Section II, I summarize my overall conclusions in response to the testimony of Mr. Oliver and Mr. Farley regarding the Company's RDR Plan.
- In Section III, I rebut Mr. Oliver's testimony that there is no need for revenue decoupling to achieve Rhode Island's energy efficiency objectives.
- In Section IV, I discuss Mr. Oliver's and Mr. Farley's concerns regarding the appropriateness and need for the package or ratemaking elements included the Company's proposed RDR Plan.
- In Section V, I respond to other criticisms on the Company's proposed RDR Plan.
- In Section VI, I address intervenor witnesses' recommendations for modifications to the Company's proposed RDR Plan.

II. Summary of Conclusions in Response to Intervenor Witnesses' Testimony on the Company's Proposed RDR Plan

Q. Please summarize the overall conclusions you reached after reviewing these witnesses' testimony on the Company's proposed RDR Plan.

A. I have carefully reviewed the testimony of the intervenor witnesses who comment on the overall purpose, structure, and specific components of the Company's proposed RDR Plan. I disagree with several themes that emerge from the testimony of Mr. Oliver and Mr. Farley. These themes are:

1. *That revenue decoupling is not a necessary element of a rate-making framework that provides distribution utilities with appropriate incentives to fully and aggressively comply with their obligations to procure cost-effective energy efficiency under the "The Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006"*

1 (“2006 Act”)¹. There is substantial literature,² in addition to common sense, that
2 supports the view that revenue decoupling is a necessary (but not sufficient) element
3 of an overall set of policies designed to assist in the goal of assuring that all Rhode
4 Island consumers get the benefit of the deployment of all cost-effective energy
5 efficiency. That goal is aimed at helping Rhode Islanders save money on their energy
6 bills, with ancillary goals related to environmental and other economic objectives in
7 the state. The literature is replete with examples of substantial barriers to
8 accomplishing such an objective, and Rhode Island policy makers have worked for
9 years in uncovering and pursuing ways to eliminate these barriers. One important
10 barrier, which revenue decoupling is designed to remove, is the inherent conflict that
11 exists between traditional ratemaking (in which utilities lose money when customers
12 conserve energy) and the goals of deploying all cost-effective energy efficiency. It
13 just makes common sense to focus on removing this barrier. The Company’s
14 proposed RDR Plan aims to do that.
15

16 2. *That the Company’s RDR Plan is somehow flawed because it goes “well beyond*
17 *standard revenue decoupling considerations”*³ and introduces other ratemaking
18 adjustments besides a plain vanilla revenue decoupling approach.⁴ This view ignores
19 the realities in the electric industry today, which include a challenging set of current
20 and future conditions for both the distribution utility and its customers. These new
21 realities warrant regulators being open to addressing fundamental ratemaking
22 challenges in new ways. These challenging set of conditions include the following
23 circumstances:

- 24 ▪ a period during which energy commodity prices faced by rate payers, but not
25 distribution rates, have risen dramatically over a decade;⁵
- 26 ▪ macroeconomic conditions that stress many customers’ ability to pay their
27 electricity bills;
- 28 ▪ a new period (or cycle) capital-investment challenges to maintain and improve
29 the quality of the distribution infrastructure to serve the requirements of
30 customers in an economy that continues to increase its reliance on electricity
31 for more and more activities, and that faces aging infrastructure;
- 32 ▪ a period in which the costs of infrastructure development are higher than
33 historical levels;

¹ See the prefiled direct testimony of Bruce Oliver (“Oliver Testimony”), pages 11-13, 19-20; prefiled direct testimony of John Farley (“Farley Testimony”), page 28-29.

² I discussed this literature at length in my prefiled direct testimony, Sections II and III.

³ Oliver Testimony, page 3.

⁴ Farley Testimony, pages 23-29.

⁵ This is true, even though natural gas prices and related wholesale electricity prices have decreased in the past year.

- conditions under which investors are more attracted to companies that are able to manage the execution, revenue recovery and financing risks associated with large investment programs they may face;
- a decade of ratemaking policies that have capped and/or frozen rates and increased the overall productivity of companies exposed to these regulatory conditions;
- macroeconomic conditions that stress many customers' ability to pay their electricity bills and challenge the utility's ability to raise capital in credit markets; and
- a continuing view that utility customers will benefit when the utility is able to attract necessary capital at reasonable cost so that the utility is able to undertake investments needed to provide quality services to those customers.

This set of conditions facing ratepayers (along with environmental concerns) has led state regulators throughout the country, as they have in Rhode Island, not only to place greater emphasis on energy efficiency as a key element of managing the cost of providing service to their state's customers, but also to hold changing expectations about the role of the utility in helping customers to better manage their energy bills (including through adoption of energy efficiency). The more aggressive emphasis on energy efficiency has led to growing interest in a new and fundamentally different ratemaking tool – revenue decoupling. Revenue decoupling has important benefits of better aligning the utility's financial interests with those of its customers in adopting cost-effective energy efficiency. But at the same time, it also introduces the complexity of inhibiting the ability of a utility to rely on internally generated funds from growth in electricity sales as a means to fund many of the investments needed to meet customer needs.

Today's conditions – including but not limited to the values associated with implementing revenue decoupling – require that regulators consider ratemaking approaches that constructively address the many infrastructure, investment, financing, and market challenges facing utilities. As some stand-alone approach to revenue decoupling will not achieve these goals, the Company has proposed the RDR Plan to both address these various challenges and place the utility in a position to be a strong partner with its customers in the implementation of cost-effective energy efficiency.

3. *That revenue decoupling introduces irresponsible regulation, either in the form of "permanent, automatic future year rate setting apparatus"⁶ and in a way that "circumvents the role of the regulator."⁷ Furthermore, the Company's RDR Plan is flawed because it is designed to provide beneficial outcomes to the Company under all circumstances while shifting risks from the Company to customers.⁸ This*

⁶ Farley Testimony, page 23.

⁷ Farley Testimony, page 23.

⁸ Farley Testimony, page 23.

perspective is based on an erroneous conclusion that that the proposed Plan would reduce regulatory oversight. In some ways, the proposed RDR Plan provides for more frequent regulatory review and oversight than has existed in many years. It does not shift risk to customers. In fact, the Company's RDR Plan resulted from an effort by the Company to satisfy several competing objectives in the context of changing conditions. The ultimate goal, of course, was to arrive at a ratemaking package that would produce just and reasonable rates for providing quality electric service to customers. And the corollary objectives included: improving the alignment of the utility's and its customers' interest in pursuing all cost-effective energy efficiency and in reducing customers' energy bills; providing appropriate incentives for the Company to make timely investment in needed distribution infrastructure for the benefit of customers; affording the Company a genuine opportunity to earn a reasonable rate of return through timely revenue recovery; sending appropriate price signals to customers about the cost to provide them with distribution service; and encouraging administrative efficiency in the overall ratemaking process. These multiple goals and objectives led the Company to propose an overall ratemaking package that: incorporates full revenue decoupling; provides timely recovery of prudently incurred investment in needed distribution plant; gives the customers a new benefit of a rate adjustment when the Company makes less capital investment than its capital-recovery expense⁹ in the test year; provides formulaic revenue adjustments for certain operating expenses¹⁰ while also giving customers the benefit of incentives for the Company to harness productivity improvements;¹¹ adjusts rates in a subsequent year based on known and measurable changes in historical indices and investment patterns;¹² and creates more manageable bites of investment for the Commission to review than exist in multi-year prudence reviews at present.

I urge the Commission to review the Company's ratemaking proposals in the context of these overall conditions. I urge the Commission to recognize that having the ability to use other regulatory tools and instruments to support revenue collection from customers in a more timely fashion will strike an appropriate balance between regulatory oversight and supervision, on the one hand, and timely cost-recovery, on the other. The combination of revenue decoupling and the current cycle of investment requirements

⁹ The amount built into base rates in the form of the depreciation expense for recovery of rate base investment.

¹⁰ Some of these revenue-recovery adjustments have been approved for other distribution companies in Massachusetts.

¹¹ This refers to the 0.5-percent productivity factor to the inflation adjustment.

¹² This refers to the Net CapEx and Net Inflation Adjustments.

1 together encourage regulators to consider adoption of innovative ratemaking approaches.

2
3 That said, every ratemaking approach has implications and trade-offs for the balance
4 between oversight and timely cost-recovery. For example, in the extreme, ratemaking
5 could remove all regulatory lag by having a rate case each day that would set rates based
6 on yesterday's costs; this would provide timely regulatory scrutiny, timely cost-recovery
7 and timely price signals to customers about the cost of rendering service, but it would do
8 so at an administrative cost of nightmarish proportions. That amount of timely cost
9 recovery would not be good for anyone. Having a process that marries periodic rate
10 cases for full-blown review of a utility's cost of service with annual proceedings that
11 review manageable bundles of incremental capital additions and reconcile actual
12 revenues with revenue targets may provide a variety of balanced benefits. It will afford
13 regulators greater ability to scrutinize capital investments outside the limitations of a full
14 rate case. It will send more timely and gradual price signals to consumers about the cost
15 of incremental investments incurred by the utility to provide reliable and efficient service.
16 And it will help enable the utility to fund some portion of its operations.

17
18 I urge the Commission to adopt an overall ratemaking package that aligns the Company's
19 interests with those of its customers, which is accomplished by the Company's proposed
20 RDR Plan. Approving new rates with revenue decoupling, and with adjustments for
21 capital expenditures and inflation, would support the accomplishment of Rhode Island's
22 goals for lower energy bills for electricity customers through adoption of all cost-
23 effective energy efficiency – as supported by the Company, as well as by CLF's witness

Ms. Cleveland and RI EERMC's witness Dr. Lowry – and would do so in a way that ensures reliable, efficient and high-quality service to Rhode Island's electricity customers.

III. Responses to Intervenor Witnesses' Testimony Regarding Whether Revenue Decoupling is Needed to Achieve Rhode Island's Energy Efficiency Objectives

Q. Mr. Oliver concludes that revenue decoupling would not have a “significant impact on the expansion of National Grid's energy efficiency programs”¹³ and is not “necessary to ensure the pursuit of improved energy efficiency by electric customers in Rhode Island.”¹⁴ Do you agree with his conclusions?

A. No. There is substantial evidence and opinion in the field to challenge and counter Mr. Oliver's general claim that revenue decoupling is not necessary for a state like Rhode Island to achieve its broader energy efficiency goals including those established in its 2006 Act.¹⁵ I discussed this literature in great detail in my direct testimony, and therefore do not repeat it here.¹⁶

There is one new relevant document, however, that I mention here, because it has been published by the Regulatory Assistance Project (“RAP”)¹⁷ since the date on which I

¹³ Oliver Testimony, pages. 32, 56.

¹⁴ Oliver Testimony, page 32.

¹⁵ The 2006 Act, Section 39-1-27.7(a)(2) requires that distribution utilities pursue least-cost “procurement of energy efficiency and conservation measures that are prudent and reliable and when such measures are lower cost than acquisition of additional supply.”

¹⁶ See Section II and III of my prefiled direct testimony.

¹⁷ As the Commission is no doubt aware but I state here for the record, “The Regulatory Assistance Project (RAP) is a non-profit organization, formed in 1992 by experienced utility regulators, that provides research, analysis, and educational assistance to public officials on electric utility regulation. RAP workshops cover a wide range of topics

1 submitted my testimony. This document was authored by former Oregon Public Utility
2 Commission staffer, Lisa Schwartz, who addresses in the September 2009 RAP
3 Newsletter the specific question of whether there is a role for revenue decoupling where
4 energy efficiency is required by law. I have attached the September 2009 Newsletter
5 (which is dedicated to this question and is entitled “The Role of Decoupling Where
6 Energy Efficiency is Required by Law”) to my testimony as Schedule NG-SFT-R-1.

7
8 The author reminds the reader of the fact that “Under traditional price-setting regulation,
9 a utility with a legal mandate to acquire energy efficiency[fn in the original] feels the
10 financial pinch of reduced sales just as it would without such an aggressive requirement,
11 only more sharply. At the same time, the utility will still have the incentive to increase
12 sales in order to increase profits. That structural conflict is at best paradoxical. At worst,
13 it makes utilities adversaries instead of motivated partners in the myriad of venues where
14 energy efficiency goals and activities are hammered out....”¹⁸ The RAP document
15 concludes that “Mounting evidence that efficiency is the least-cost, least-risk energy
16 resource is leading to increasingly aggressive savings requirements. Climate change
17 mitigation strategies compound this trend. However, neither requirements in law nor

including electric utility restructuring, power sector reform, renewable resource development, the development of efficient markets, performance-based regulation, demand-side management, and green pricing. RAP also provides regulators with technical assistance, training, and policy research and development. RAP has worked with public utility regulators and energy officials in 45 states, Washington D.C., Brazil, India, Namibia, China, Egypt, and a number of other countries. RAP principals and associates have also written and spoken extensively on energy policy and regulation. RAP Issuesletters, published quarterly, and RAP’s many in-depth reports and conference presentations provide serious and thoughtful discussion of cutting-edge issues in industry restructuring (e.g. market power, stranded costs, system benefits charges, customer choice, and consumer protection), and other current topics (e.g. resource portfolio management, policies for distributed generation and demand-side resources, distribution system regulation, reliability and risk management, rate design, electrical energy security, and environmental protection).” <http://www.raponline.org/#top>.

¹⁸ Schwartz, Lisa, “The Role of Decoupling Where Energy Efficiency is Required by Law”, Regulatory Assistance Project Issuesletter, September 2009, p. 4.

1 third-party administration of programs negate efficiency's fundamental conflict with the
2 traditional utility business model, where earnings fall disproportionately with declining
3 energy sales. Decoupling, which eliminates the conflict, is therefore a key policy tool for
4 achieving high levels of energy savings through performance standards like an EERS
5 [Energy Efficiency Resource Standards] as well as traditional utility programs, building
6 codes, equipment standards, and consumer education.”¹⁹

7
8 **Q. Please connect these conclusions to Mr. Oliver's opinion that revenue decoupling is**
9 **not “necessary to ensure the pursuit of improved energy efficiency by electric**
10 **customers in Rhode Island.”²⁰**

11 A. Revenue decoupling is an essential element of new ratemaking policies and programs
12 needed if Rhode Island is to fully achieve its broad energy policy goals and, in particular,
13 its goals for expanded energy efficiency. These goals are critical to helping Rhode
14 Islanders manage and reduce their high-cost energy bills and rely on cost-effective energy
15 efficiency as a way to reduce the high-priced commodity portion of their electricity bills,
16 which has become the dominant part of these bills in recent years. As the RAP
17 newsletter states, under traditional regulation, at best there is a “structural conflict”
18 between the utility's financial interests and the customers' interest in reducing their
19 energy use. Revenue decoupling eliminates this structural conflict and therefore is one of
20 the necessary ratemaking elements needed to align the incentives of distribution utilities
21 and their customers in the full and aggressive implementation of cost-effective energy

¹⁹ See Schedule NG-SFT-R-1, pages 4-5.

²⁰ Oliver Testimony, page 32.

1 efficiency. This latter point is explained in detail not only in my own prefiled direct
2 testimony, but also in the testimonies of Ms. Cleveland and Mr. Lowry. Mr. Oliver's
3 testimony reveals a failure to appreciate the key role of revenue decoupling in achieving
4 these goals *for the benefit of customers*.

5
6 Furthermore, Mr. Oliver fails to appreciate the many barriers to implementation of cost-
7 effective energy efficiency and the distribution utility's unique relationship with its
8 customers that can be leveraged to overcome these barriers. He writes:

9 Decisions to implement energy efficiency/conservation measures are primarily
10 customer decisions, not utility decisions. Although the Company may assist
11 customers in identifying opportunities to improve energy efficiency in the
12 residences, offices, or other facilities, there are other non-regulated entities in the
13 market place who are also working actively to encourage customer investment in
14 energy efficiency programs and equipment. The Commission must remember
15 that the encouragement of energy efficiency is **NOT** a monopoly service.²¹
16

17 These statements miss the mark on several fronts. First, ratemaking policies designed to
18 align better the financial incentives of the distribution utility with the economic interests
19 of its consumers are not about determining whether a utility is or is not a monopoly
20 provider of energy efficiency services. They are about establishing ratemaking policies
21 for the distribution utility (as a monopoly provider of distribution service) that are aligned
22 with adoption of all cost-effective energy efficiency – whether implemented purely as a
23 function of the customer's own independent actions, or assisted by a third-party provider
24 of energy efficiency services, or supported by energy efficiency programs administered
25 by the distribution utility, or accomplished through any other means. No matter the

²¹ Oliver Testimony, page 32.

1 source of that energy efficiency action, under traditional ratemaking approaches the
2 distribution utility's financial interests are adversely affected by reductions in energy use.
3 When energy efficiency lowers energy use, it lowers the utility's distribution revenues.
4 And the point is to break that inherent conflict.

5
6 That goal is particularly important given the critical role that the utility is expected to
7 play in assisting in deploying energy efficiency for the benefit of consumers. For
8 example, the distribution utility (along with competitive energy service providers) can
9 have a pivotal role in identifying and helping to implement such investments and
10 measures on behalf of the customer. Mr. Oliver fails to appreciate the fact that, because
11 of well-recognized market barriers and failures that limit the full adoption of cost-
12 effective energy efficiency by the utility's customers, it is profoundly helpful (among
13 other things) to make full use of the unique customer relationship between the
14 distribution utility and its customers if full deployment of cost-effective energy efficiency
15 is to become a reality. Simply "relying upon the market" will not be sufficient to induce
16 all cost-effective energy efficiency and to provide meaningful assistance to Rhode Island
17 electricity consumers to help them lower their electricity bills. Revenue decoupling is
18 designed to take full advantage of this unique relationship by removing the inherent
19 financial conflict between the utility's interests and those of its customers.

20
21 **Q. Mr. Oliver notes that the Company's current rates include other forms of revenue**
22 **decoupling.²² Are these forms of decoupling sufficient to provide the incentives**

²² Oliver Testimony, page 22.

1 **needed for the Company to pursue all cost-effective energy efficiency?**

2 A. No. While the Company does receive a portion of its revenues from customer charges
3 that would be unaffected by increased energy efficiency, based upon Mr. Oliver's
4 Schedule DIV-BRO-1, these charges appear to be less than 30 percent of total revenues
5 for every rate class.²³ Thus, for all rate classes, 70 percent or more of the revenues come
6 from per-kWh or per-kW charges that would be potentially reduced with implementation
7 of energy efficiency measures. Consequently, the Company's customer charges are
8 insufficient to fully decouple revenues from sales or appreciably change the Company's
9 incentives to pursue energy efficiency.

10
11 Mr. Oliver is also technically incorrect in several of his claims regarding ways in which
12 elements of the Company's current rates decouple revenues from sales. First, he suggests
13 that collection of revenues through demand charges removes a utility's disincentive to
14 promote energy efficiency. This claim, however, is incorrect since energy efficiency and
15 other demand-side programs and measures can reduce customers' peak loads and
16 therefore the level of the demand-related services they must purchase from the Company.
17 Thus, increased energy efficiency could result in lower demand-related revenues to the
18 Company. Second, Mr. Oliver argues that accounting for the impact of the Company's
19 energy efficiency and demand-side programs in the forecasts used to set base rates
20 somehow decouples revenues from sales. Again, this is clearly incorrect. Once the
21 Company's rates are set, the incentive to increase sales is the same regardless of whether

²³ The one exception is the Electric Propulsion rate class, although this class represents less than 0.2% of the Company's total revenues.

1 or not those rates reflect anticipated reductions in sales from energy efficiency. Mr.

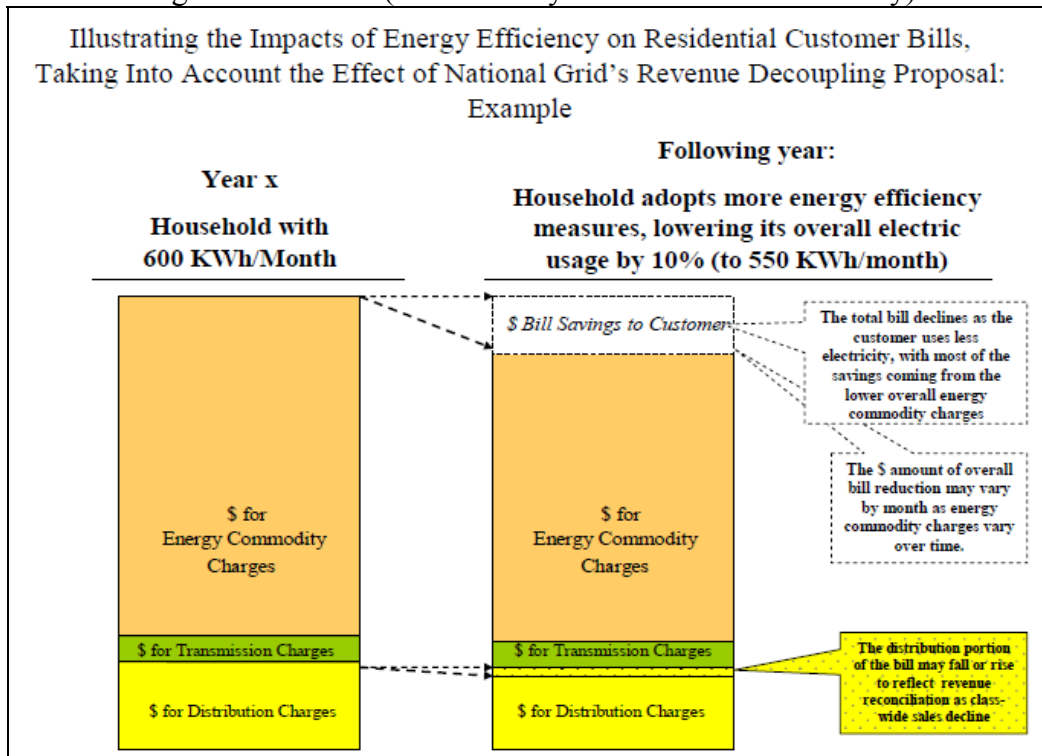
2 Oliver appears not to recognize the fact that the *disincentive* for energy efficiency created
3 by traditional regulation arises from the fact that rates are fixed at pre-determined levels
4 rather than the mechanics of how those rates are initially set.

5
6 **Q. Mr. Oliver seems to suggest that revenue decoupling would reduce incentives for**
7 **energy efficiency because it would “distort customers’ perceptions of the**
8 **relationship between energy usage and monthly billed charges for electric service.”²⁴**
9 **Do you agree with that conclusion?**

10 A. No. While Mr. Oliver is not completely transparent about the distortion to which he
11 refers, he appears to point to the situation where reductions in a customers’ energy use
12 would lead to a small increase in rates to recapture lost revenues. He appears concerned
13 that this offsetting effect on rates would distort customers’ incentives to undertake energy
14 efficiency. However, this effect is inconsequential. Compared to the overall bill impacts
15 that a participating customer would likely experience as a result of reducing energy use
16 and avoiding not only distribution rates but the commodity and transmission-related
17 portion of the bill as well, the type of rate impact on the distribution charge would likely
18 be imperceptible to almost any energy user. This was illustrated in Figure NG-SFT-4 in
19 my prefiled direct testimony (reproduced here, below).

²⁴ Oliver Testimony, pages 56.

Figure NG-SFT-4 (from Tierney Prefiled Direct Testimony)



Notably, the Massachusetts' Department of Public Utilities ("DPU") reached this same conclusion, stating: "we expect that the impact on any one customer's distribution charge as a result of his or her own actions to reduce sales is likely to be unnoticeable because the reconciled revenues will be recovered from all customers."²⁵ (I note this determination of the Massachusetts DPU not because it is dispositive, since of course it is not, but rather to underscore the point I am trying to make.²⁶)

²⁵ Massachusetts DPU, Order, Docket 07-50-A, July 16, 2008, page 59.

²⁶ Mr. Oliver seems to question the attention I paid in my prefiled direct testimony to the activities in other states, when he asks "Should this Commission be compelled by the decisions of Commissions in certain other jurisdictions to implement revenue decoupling? A. No." (Oliver Testimony, page 20.) By informing the Commission of actions in other jurisdictions, I am not meaning to suggest that these other decisions compel a similar result in Rhode Island; rather, my intention is to provide information to enhance the record on which the Commission will draw as it exercises its own discretion and reaches its own judgment.

1 While focusing upon the inconsequential impact of revenue decoupling on distribution
2 rates, Mr. Oliver fails to consider the significant financial savings that increased energy
3 efficiency would create by reducing customer's energy commodity purchases, which are
4 by far the largest component of their monthly energy bills. In fact, increases in these
5 potential savings through the full and aggressive engagement of the Company and its
6 customers in promoting all cost-effective energy efficiency represent the greatest
7 potential benefit to customers from the Company's revenue decoupling proposal.
8

**IV. Response to Intervenor Witnesses' Concerns Regarding the Appropriateness and
Need for the Set of Ratemaking Elements Included within the Company's RDR Plan**

9 **Q. Mr. Oliver contends that the Company's RDR Plan "reaches well beyond standard
10 revenue decoupling considerations to introduce what is essentially a form of
11 alternative ratemaking."²⁷ Do you agree with this assessment?**

12 **A.** Yes and no. I agree in some sense with Mr. Oliver that the Company's proposal goes
13 beyond "standard" revenue decoupling, if by "standard" he means a ratemaking approach
14 that simply decouples revenues from sales through a periodic revenue reconciliation that
15 compares actual revenues with a fixed total revenue requirement (or even one in which
16 the revenue requirement was adjusted based on changes in the number of customers). He
17 and I both agree that the Company's proposed RDR Plan involves more than that.
18 However, as I described in my prefiled direct testimony, such a simple "plain vanilla"
19 stand-alone revenue decoupling mechanism neither would be well matched to the
20 Company's current operating, market and financial circumstances, nor would it constitute

²⁷ Oliver Testimony, page 3.

1 a “standard” form of implementing revenue decoupling from the perspective of the actual
2 ratemaking approaches used by utilities that have actually implemented revenue
3 decoupling.

4
5 As described in great detail in my prefiled direct testimony (and in those of Mr. Tom
6 King and Mr. John Pettigrew from National Grid), the Company’s current operating,
7 market and financial circumstances include an aging infrastructure requiring increased
8 levels of investment, a market with rising costs of providing service and particularly
9 undertaking infrastructure investment needed to maintain reliability, and financial
10 markets that are providing diminished access to credit and capital compared to recent
11 historical periods. These circumstances necessitate more dynamic ratemaking
12 mechanisms that will allow the Company’s revenue requirements to adjust more actively
13 to these changing conditions. In the absence of the other ratemaking mechanisms and in
14 the presence of its high future capital requirements, the Company will need to rely upon
15 frequent rate case filings; otherwise, the situation would leave the Company in a position
16 of continuously falling behind in its efforts to fully recover its costs and its allowed rate
17 of return.

18
19 Because of these operating, economic and financial circumstances, which are not
20 completely unique to the Company’s circumstances, many other utilities in New England
21 and in other parts of the country have also implemented (and/or are considering
22 proposing) complementary ratemaking elements, similar to those proposed by the
23 Company. (Even in situations where companies are not proposing revenue decoupling,

1 there is growing interest in innovative ratemaking approaches to address the rising
2 investment-cost outlook and investor concerns about the implications of growing
3 regulatory lag.²⁸ See Schedule NG-SFT-R-2.) These complementary elements provide
4 greater assurance that the utilities can sustain the investment needed to maintain reliable,
5 high quality service while also aggressively supporting the pursuit of cost-effective
6 energy efficiency.

7
8 As I described in my prefiled direct testimony, other utilities utilizing revenue decoupling
9 have implemented many of the same rate-making elements proposed by the Company,
10 including various mechanisms to allow for improved recovery of capital expenditures
11 (e.g., future test years, adjustments for capital spending) and inflation (or “attrition”)
12 adjustments for all or a portion of the utility’s revenue requirements.²⁹ Thus, while
13 revenue decoupling is still used in a relatively small number of jurisdictions,³⁰ it is not
14 uncommon for ratemaking plans used by utilities with revenue decoupling to include
15 many additional ratemaking elements that allow the utilities to replace the growth in
16 revenues that is lost when the utility can no longer rely upon increases in the number of

²⁸ “Having certain rules in place allows for more consistent, timely, and transparent regulation over time. Features we assess in this category are: Test Year Period, Fuel Clauses, Non-Fuel Spending Trackers, Statutory Decision Limits, Formal IRP Processes, CWIP vs AFUDC, and Decoupling mechanisms.” Barclays Capital, “Utilities: Capital Management,” July 16, 2009, Page 23. For convenience, I have provided this document as Schedule NG-SFT-R-3.

²⁹ See Exhibit NG-SFT-3. See also Exhibits NG-SFT-R-1, NG-SFT-R-2, and NG-SFT-R-3.

³⁰ Mr. Oliver suggested that in my prefiled direct testimony, I was trying to suggest that revenue decoupling is prevalent around the country. (See Oliver Testimony, page 20.) That was not my intention. My purpose was to mention the growing interest among state regulators to consider revenue decoupling mechanisms, and to discuss the experience of states and utilities where it has been adopted. As indicated in my prefiled direct testimony and further amplified by a more recent comprehensive review of revenue decoupling by electric and natural gas utilities, there is still a limited number of settings in which it has been formally adopted. According to Pam Lesh’s study for RAP, “A total of 28 natural gas local distribution gas utilities (LDCs) and 12 electric utilities, across 17 states, have operative decoupling mechanisms.[fn] Six other states have approved decoupling in concept, through legislation or regulatory order, but specific utility mechanisms are not yet in place.” See Exhibit NG-SFT-R-2, page 3.

1 customers and increases in the energy use per customer. This loss of revenues was
2 recognized by the Massachusetts DPU in its recent Decoupling Order. With regard to
3 capital expenditures, for example, it noted:

4 To the extent that distribution companies make capital expenditures to replace
5 existing assets, the magnitude of capital replacement required has little or no
6 correlation with levels of customer growth. Instead, capital expenditures are
7 influenced by factors such as the age of the assets, changes in technology, past
8 patterns of customer growth, and increases in the load to serve. Under these
9 conditions, distribution companies' rates may not adequately provide for recovery
10 of capital replacement expenditures that are incurred after the rate year if the
11 reconciliation of revenues is based solely on a customer growth adjustment... A
12 decoupling mechanism should not undermine a distribution company's ability to
13 obtain adequate funding for needed infrastructure maintenance and upgrade
14 projects.³¹
15

16 Based on these considerations, the DPU concluded that it would "consider company-
17 specific ratemaking proposals that account for: (1) the impact of capital spending on a
18 company's required revenue target."³² Thus, Massachusetts regulators recognized that the
19 implementation of revenue decoupling to achieve the state's goal of pursuing all cost-
20 effective energy efficiency could require new ratemaking elements to address capital
21 costs and inflationary pressures on costs in ways that provide distribution companies to
22 opportunity to fully recover their costs.
23

24 **Q. In light of these factors, do you agree with Mr. Oliver that "[t]he Commission**
25 **should reject both National Grid's proposed RDR plan and RDM, finding that those**
26 **proposals represent inappropriate, inequitable, and unjustified departures from**

³¹ Massachusetts DPU, Order, Docket 07-50-A, July 16, 2008, pages 49-50.

³² Massachusetts DPU, Order, Docket 07-50-A, July 16, 2008, page 50.

1 **traditional ratemaking practices and principles”?**³³

2 A. No. The Company’s RDR Plan is designed to align the Company’s interests with the
3 achievement of Rhode Island’s policy goals of procuring cost-effective energy efficiency,
4 helping customers to better manage and lower their total electric bills (including
5 commodity and transmission service, as well as distribution service) and maintaining
6 reliable and high quality service. As described above, although revenue decoupling is an
7 essential element of a regulatory policy designed to align the distribution utility’s
8 interests with its customers, it is also true that introducing revenue decoupling in
9 situations where there are rising investment requirements means that the former must be
10 coupled with complementary ratemaking elements, including inflation adjustments and
11 mechanisms for recovering growing capital investment, that provide the utility with
12 sufficient revenues to fully recover costs. (In fact, these innovative ratemaking
13 approaches may well have been needed even in the absence of revenue decoupling. See
14 Schedule NG-SFT-R-2.) Other regulators, in recognition of these relationships, have
15 paired revenue decoupling with companion ratemaking elements identical to or similar to
16 those proposed by the Company. Further, the RDR Plan, while proposing changes from
17 traditional ratemaking as implemented in Rhode Island, is consistent with the underlying
18 cost-of-service principles that form the foundation of that tradition, including rates
19 grounded in an approved revenue requirements, capital expenditures adjustments
20 reflecting expenses approved by the Commission as prudent, used and useful, and annual
21 filings of all other rate adjustments for Commission review. Consequently, I strongly
22 urge the Commission to place no weight on Mr. Oliver’s concerns regarding the fact that

³³ Oliver Testimony, page 8.

1 the Company's proposal includes ratemaking changes beyond a simple revenue
2 decoupling mechanism.

3
4 **Q. Are there other aspects of Mr. Oliver's testimony that suggest he fails to appreciate**
5 **the Company's operational, economic and financial circumstances that underlie the**
6 **design of the Company's RDR Plan?**

7 A. Yes. Mr. Oliver comments on Figure NG-SFT-15 of my direct testimony, indicating that
8 the revenue deficiencies under a fixed total revenue requirement would not have adverse
9 consequences for the Company's financial position.³⁴ He is incorrect on several fronts.
10 First, Figure NG-SFT-15 was developed as a purely illustrative calculation, and not an
11 analysis of the Company's particular investment, financial and economic circumstances,
12 a point Mr. Oliver appears not to recognize. Figure DIV-11-37-2 in the Company's
13 response to Division Data Request 11-37 reports results of this same analysis using
14 information specific to the Company. Thus, Mr. Oliver draws inferences about the
15 implications of a fixed revenue requirement from the wrong exhibit.

16
17 Second, his analysis of Figure NG-SFT-15 "adjusted to reflect more realistic numbers for
18 National Grid in this proceeding"³⁵ is clearly inconsistent with estimates developed as
19 part of the Company's response to Division Data Request 11-37, which found that the
20 Company would be short nearly \$70 million annually by 2013, or more than 20 percent
21 of the amount needed for full recovery in 2013 of \$345 million. Whereas the Company's

³⁴ Oliver Testimony, pages 30-31.

³⁵ Oliver Testimony, page 31.

1 response was based upon reasonable assumptions consistent with the instant rate filing
2 (as identified in the response Division Data Request 11-37), Mr. Oliver provides no
3 documentation of his analysis, thus making it impossible to compare these analyses to
4 identify differences in assumptions that lead to the significant discrepancy in results.

5
6 Finally, Mr. Oliver seems to take the position that it would reasonable for the
7 Commission to implement a ratemaking approach that assumes that the Company would
8 experience a steady erosion of its earnings so long as the magnitude of that erosion was
9 within a range that did not “alarm” regulators. This viewpoint is inconsistent with the
10 traditional regulatory principle that the utility should be allowed a reasonable opportunity
11 to earn a sufficient return on investment to attract necessary capital to fulfill its obligation
12 to serve its customers with reliable and high quality service. Adopting his point of view
13 would deny the Company of this opportunity.

14
15 **Q. Mr. Farley seems to suggest that the Company’s RDR Plan is inconsistent with**
16 **requirements in the 2006 Act.³⁶ Do you agree with this assessment?**

17 A. No. The 2006 Act clearly³⁷ provides the Commission with discretion to implement
18 ratemaking policies in the event that implementation of energy efficiency procurement
19 and system reliability measures (within the context of current market conditions) limits
20 the Company’s ability to fully recover its costs:

³⁶ Farley Testimony, pages 28-29.

³⁷ In offering this opinion, I do not intend to suggest that I am rendering a legal opinion (since I am not a lawyer); rather, my opinion is based on my prior regulatory experience in positions that required me to interpret statutes.

1 If the commission shall determine that the implementation of system reliability
2 and energy efficiency and conservation procurement has caused or is likely to
3 cause under or over-recovery of overhead and fixed costs of the company
4 implementing said procurement, the commission may establish a mandatory rate
5 adjustment clause for the company so affected in order to provide for full
6 recovery of reasonable and prudent overhead and fixed costs.³⁸
7

8 While also recognizing that the Commission has such authority, Mr. Oliver concludes
9 that “the Company has proposed a far more sweeping set of rate adjustments that not only
10 decouples revenues from sales but also decouples revenues from prudent and reasonable
11 costs!”³⁹ While long on hyperbole, this conclusion is short on substance. His conclusion
12 appears to rely on no understanding of the impact of energy efficiency procurement (or
13 system reliability measures) has upon the Company’s recovery of its legitimate cost of
14 providing service to customers. In light of my prior discussion of this same issue above, I
15 do not repeat the reasons here.
16

V. Responses to Other Concerns Regarding the Company’s RDR Plan

17 **Q. Mr. Farley contends that the Company’s RDR Plan is “essentially an automatic rate**
18 **case”⁴⁰ (a “permanent, automatic future year rate setting apparatus”⁴¹), that it**
19 **“claims to simulate the workings of a real rate case, but it does so in a way that pre-**
20 **determines a beneficial outcome for the utility,”⁴² and that it “circumvent[s] the role**

³⁸ The 2006 Act, Section 39-1-27.7(d).

³⁹ Farley Testimony, page 29.

⁴⁰ Farley Testimony, page 25.

⁴¹ Farley Testimony, page 23.

⁴² Farley Testimony, page 25.

1 **of the regulator.”⁴³ Do you agree with this assessment?**

2 A. No. The Company’s RDR Plan is designed to ensure that the Company collects no more
3 and no less than its approved revenue requirements. These revenue requirements would
4 be those approved by the Commission in this instant rate proceeding, with annual
5 adjustments to this revenue requirement to reflect (1) actual capital expenditures
6 approved by the Commission as prudent, used and useful (though the Net CapEx
7 Adjustments) and (2) changes in costs, as measured by an independent, third-party index
8 of economy-wide costs, for elements of the Company’s cost of service that would be too
9 costly to review through annual rate proceedings (i.e., the Net Inflation Adjustment.)
10 These adjustments are similar to the types of ratemaking decisions made by regulators in
11 a rate case, and under the RDR Plan would be no more automatic nor evading of
12 regulatory oversight than the types of reviews and determinations made by regulators in
13 its other adjudicatory proceedings.

14
15 As described at length in my pre-filed direct testimony, these proposed annual
16 adjustments are necessary if the Company is to fully recover its costs given the
17 elimination of year-to-year growth in total revenue requirements under revenue
18 decoupling, growing investment needs due to the Company’s aging infrastructure, and
19 rising costs of providing service and undertaking needed investments. These adjustments
20 do not, however, circumvent the role of the regulator in adjudicating issues in contested
21 proceedings or substitute for rate case proceedings. Under the Company’s proposed
22 RDR Plan, the regulator would still carry out the following assessment and oversight: (1)

⁴³ Farley Testimony, pages 23, 25.

1 Commission approval of a revenue requirement in the context of a full rate case
2 proceeding; (2) Commission review of two filings each year that would provide details of
3 the Company's capital expenditures over the most recent periods, and upon which the
4 Commission would make determinations as to what portions of those capital investments
5 are prudent, used and useful before they are incorporated into the Company's Cumulative
6 Net CapEx Adjustment; (3) Commission verification of changes in the third-party market
7 indices that affect the Net Inflation Adjustment on an annual basis and that serve to
8 modify previously identified portions of the Company's operations and maintenance
9 costs from the rate case; (4) Commission approval in this rate case of an offset (proposed
10 to be set at 0.5 percentage points, to reflect a productivity offset and/or a customer
11 dividend) to use each year to adjust the results of the inflation index each year; and (6)
12 the Commission's ability to exercise its general supervisory authority over the
13 Company's rates, including the authority to require that the Company file for a rate case
14 at some point in the future.

15
16 This set of filings and procedurals steps, in combination with the Commission's broad
17 authority, provides a degree of enhanced supervision relative to traditional ratemaking.
18 So, while Mr. Farley suggests that "The extensive use of automatic adjustment makes it
19 very difficult for the regulator to have the whole story before approving rate increases,"⁴⁴
20 the Commission actually receives more information, more frequently regarding the
21 Company's actual costs under its proposed RDR Plan than it would under traditional
22 regulation.

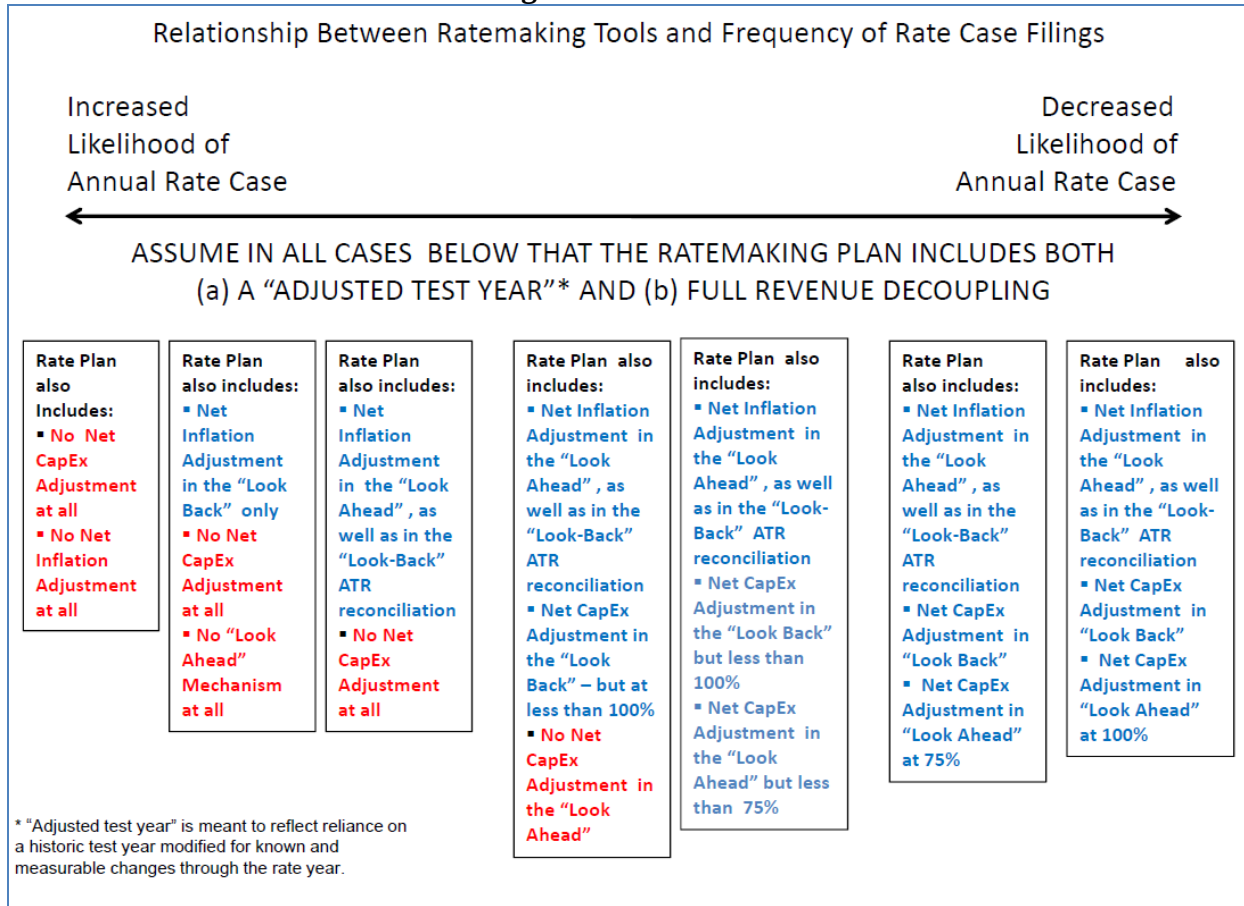
⁴⁴ Farley Testimony, page 25.

1 **Q. Mr. Oliver also states that “The Company’s RDR Plan is not an appropriate**
2 **substitute for base rate proceedings.”⁴⁵ Do you believe that the Company’s RDR**
3 **Plan is designed to substitute for base rate proceedings?**

4 A. No. The Company’s RDR Plan is designed to provide interim adjustments to rates
5 between base rate proceedings that will avoid the need for unnecessarily frequent base
6 rate proceedings that tax the resources of the Commission, the Company and third
7 parties, and impose unnecessary costs on Rhode Island electricity consumers. (I have
8 prepared Figure NG-SFT-R-1 to illustrate the trade-offs associated with the inclusion of
9 various ratemaking elements – including test-year policy, revenue decoupling
10 mechanisms, and inflation adjustments – and the general frequency of rate cases in an
11 environment of rising investment requirements and the presence of regulatory lag. As
12 shown, the addition of ratemaking elements allows for the more timely recovery of
13 investment and other expenses, and serves to reduce regulatory lag relative to ratemaking
14 packages toward the left of the illustration.) The Company’s proposal is not designed to
15 substitute for full rate case proceedings, since the Company anticipates that it would
16 continue to file base rate cases in the future and the Commission could require that the
17 Company make such a filing if it was concerned that the time since the Company’s last
18 filing has been too long or that the certain elements of the Company’s cost of service that
19 affects its revenue requirements have appreciably diverged from revenue requirements
20 (e.g., operations and maintenance costs, cost of capital, depreciation, etc.).

⁴⁵ Oliver Testimony, page 4.

Figure NG-SFT-R-1



Q. What is your response to Mr. Oliver's comment that "no witness on behalf of the Company offers a comparable illustration of the ratepayer impacts that can be expected from the Company's RDR Plan on a class-by-class basis"⁴⁶?

A. While I agree that the Company's direct submission does not include an analysis of the rate impact of the proposed RDR Plan, I do not agree with the implication that the filing is somehow deficient. I agree with CLF Witness Cleveland that it is legitimate for the Commission and other parties to attempt to understand the rate-impact implications of

⁴⁶ Oliver Testimony, page 15.

1 revenue decoupling,⁴⁷ but doing so prospectively with a view that such an analysis would
2 accurately portray the future implications of revenue decoupling could run the risk of
3 adding speculative evidence into the record.⁴⁸ Because the amount of revenue to be
4 reconciled in any year will be subject to various forces – e.g., weather, speed of economic
5 recovery, customer migration in or out of RI, customers’ adoption of electricity-using
6 devices, deployment of energy efficiency – it would be speculative to analyze rate
7 impacts.⁴⁹

8
9 The record may be informed, however, by results from a new study that has been
10 published since the date on which I submitted my own testimony in this proceeding. This
11 new study sheds light on rate impacts associated with revenue decoupling mechanisms
12 adopted by electric and natural gas utilities in other states. This study, authored by Ms.
13 Pamela Lesh for the Regulatory Assistance Project⁵⁰ (“Lesh Report”), is a comprehensive
14 assessment of revenue decoupling mechanisms adopted by state commissions and utilities

⁴⁷ On pages 14-15 of her prefiled direct testimony, Ms. Cleveland expresses her view that it is unfortunate that Grid did not provide a more responsive answer to Division Information Request 6-5, in light of the legitimate concern over ratepayer impacts. Because I agree with her that it is a legitimate concern, I want to clarify that I did not mean in any way to disrespect the Division’s interest in this issue or the Commission.

⁴⁸ This is, in part, what I had in mind in responding to the Division’s Information Response 6-5, where I responded that “Neither the Company nor Dr. Tierney has performed research on the magnitude of revenue deferrals or rate adjustments for utilities with rate adjustment mechanisms that are comparable to the Company’s proposed RDR Plan. Such research would need to identify any differences in rate adjustment mechanisms between the Company’s proposed RDR Plan and the rate adjustment mechanisms used by other utilities are identified, and assess the implications of these differences on rate adjustment mechanisms performance (in terms of rate adjustment magnitude and deferral amounts).”

⁴⁹ Ironically, Mr. Oliver makes a similar point when he criticizes my reliance on a 1994 study which analyzed (among other things) the impacts of revenue decoupling on rate volatility. He notes that examining the impact of revenue decoupling was confounded by the fact that it was already in place, and as such the authors’ analysis “cannot reliably assess the wide array of economic, financial, and political factors that might have influenced (a) the timing of rate increase requests in the absence of revenue decoupling and/or (b) the actions utility management may have taken to control costs in the absence of revenue decoupling, (c) the size of rate increase requests, and (d) the outcomes of traditional rate proceedings.” Oliver Testimony, page 23.

⁵⁰ http://www.raponline.org/docs/GSLLC_Lesh_CompReviewDecouplingInfoElecandGas_2009_06_30.pdf

1 around the country. (Although a copy of the study was included as Exhibit A to Ms.
2 Cleveland's testimony, for convenience, I attach the Lesh Report to my testimony as
3 Schedule NG-SFT-R-3.) Based on the author's review of all revenue decoupling
4 mechanisms in operation in the U.S., she concludes that "Decoupling adjustments tend to
5 be small, even miniscule. Compared to total residential retail rates, including gas
6 commodity and variable electricity costs, decoupling adjustments have been most often
7 under two percent, positive or negative, with the majority under 1 percent.[fn] Using
8 Energy Information Administration (EIA) data for 2007 on gas and electric consumption
9 per customer and average rates, this amounts to less than \$1.50 per month in higher or
10 lower charges for residential gas customers and less than \$2.00 per month in higher or
11 lower charges for residential electric customers."⁵¹

12
13 **Q. Mr. Farley also contends that the Company's RDR Plan adjusts rates "in a way that**
14 **pre-determines a beneficial outcome for the utility."**⁵² **Do you agree?**

15 A. No. The Company's RDR Plan is designed to provide the Company with full recovery of
16 its costs of providing service, but no more than such costs. The foundation for rates
17 would be the revenue requirement approved by the Commission in the instant rate case,
18 with any subsequent adjustment to such rates being grounded in either investment
19 expenditures that have been reviewed and approved by the Commission, or cost
20 adjustments as approved by the Commission and reflecting economy-wide changes in
21 prices less a productivity offset for the benefit of consumers. In fact, rather than "pre-

⁵¹ See Schedule NG-SFT-R-2, page 4.

⁵² Farley Testimony, page 25.

1 determin[ing] a beneficial outcome for the utility,” the Company’s proposal is designed
2 to address factors that would *prevent* the Company from fully recovering its costs of
3 providing service given regulatory lag in the recovery of growing investment costs. This
4 regulatory lag results from the combination of (1) growing investment required to address
5 aging infrastructure and to absorb rising capital-investment-related input costs, and (2)
6 the elimination of growth in revenues arising from reductions in sales growth. Thus, the
7 RDR Plan does not pre-determine a beneficial outcome for the Company, but provides a
8 ratemaking environment in which the Company has a genuine opportunity – but not a
9 guarantee – to recover its cost of service, including its approved cost of capital, and avoid
10 a situation in which it must repeatedly and frequently return to the Commission for costly
11 rate cases after failing to fully recover these costs.

12
13 **Q. Mr. Farley also argues that one benefit to the Company of the RDR Plan is that it**
14 **“shifts risks from the Company shareholders to Rhode Island ratepayers without**
15 **any commensurate benefit flowing back to Rhode Island ratepayers.”⁵³ Do you**
16 **agree with this assessment?**

17 **A.** No. The Company’s RDR Plan clearly does not shift risks from the Company to its
18 customers, but instead introduces greater sharing of the risks associated with normal
19 variations in customer loads between the Company and its customers. Under traditional
20 rate making, customers’ distribution charges would rise and fall with the quantity of
21 energy consumed, thus subjecting them to uncertainty regarding the total size of their
22 monthly energy bills. By contrast, revenue decoupling provides customers with a form

⁵³ Farley Testimony, page 23.

1 of insurance that eliminates variation in their total distribution-related payments by
2 refunding any overpayment or charging for any underpayment in under following year.
3 Thus, variation in the distribution portion of monthly bills that arises from a wide variety
4 of factors is largely eliminated when actual monthly payments and reconciliations
5 adjustments in the following year are taken into account.
6

7 Under traditional regulation without revenue decoupling, both the utility and the
8 customer may face higher risk from uncertainty in revenue collection. Shareholders bear
9 the risk of revenue erosion from such things as lower-than-normal weather, lower-than-
10 normal economic activity, and higher investment requirements than the amounts
11 embedded in rates.⁵⁴ Conversely, customers face the risk that total payments will be
12 higher than allowed revenue requirements as a result of such things as abnormally hot
13 and/or cold weather, higher-than-normal economic activity, and lower investment
14 spending than the amounts embedded in rates.⁵⁵ Given this symmetry, to the extent that
15 revenue decoupling impacts risk at all, it would reduce risks for both the utility and
16 customers, rather than shifting risk from customers to the utility.
17

18 **Q. Mr. Oliver says that he finds the RDR Plan “to be less focused on providing benefits**
19 **for Rhode Island ratepayers and more focused toward ensuring benefit for the**
20 **Company and its shareholder, National Grid, U.S.A. An alternative interpretation**

⁵⁴ In other words, requirement to add more capital investment in any year than is supported by depreciation expenses built into rates.

⁵⁵ In other words, capital investment by the utility at levels below the amount supported by depreciation expenses built into rates.

1 **of the Company’s presentation might characterize the primary objectives of**
2 **National Grid’s RDR plan in this proceeding as: Providing the Company and its**
3 **shareholder[s] greater assurance of revenue collections and earnings regardless of**
4 **performance.”⁵⁶ Do you believe his conclusions accurately characterize the impact**
5 **of the RDR Plan on the financial risks faced by the Company and the impact on the**
6 **Company’s incentives to perform efficiently and with high quality of service?**

7 A. No. Although the RDR Plan would reduce variation in the Company’s revenue stream
8 (and thus provide greater assurance of *revenue levels*) as compared to revenues under
9 traditional rates, it does not provide “greater assurance of ... earnings regardless of
10 performance.” Earnings, of course, are the difference between the revenues received by a
11 company and the many costs it incurs to provide service to its customers. Even though
12 revenue decoupling would reduce variation in the revenue part of the earnings equation,
13 the Company would still face significant risk from the cost part of the earnings equation
14 due to factors such as the actual cost of capital, the Company’s actual operating and
15 maintenance costs, and regulatory lag during the year in which infrastructure investments
16 are made. The Company’s ability to earn a particular return would depend upon its
17 success in managing these costs.

18
19 Further, while the proposed RDR Plan would provide important revenue support through
20 the Net CapEx and Net Inflation Adjustments to address rising costs of providing service
21 and to allow more timely recovery of costs, there is no guarantee that these adjustments
22 will allow the Company to offset actual increases in costs. First, the adjustments do not

⁵⁶ Oliver Testimony, page 20.

1 fully eliminate regulatory lag for new capital expenditures. Second, there would still be
2 no guarantee that the adjustments for operations and maintenance costs would be
3 sufficient to offset increases in the Company's actual operations and maintenance costs
4 given increases in the cost of labor, materials and other inputs combined with
5 unanticipated and variable operating conditions that can lead to increases in costs.
6

7 **Q. Does Mr. Farley further suggest that “[t]here are ratepayer protections built into**
8 **the traditional ratemaking approach”⁵⁷ that are not present under revenue**
9 **decoupling, and that the Company’s plan “turns that regulatory principle on its**
10 **head”⁵⁸?**

11 A. Yes he does, but in my opinion, his conclusion reflects not only a flawed understanding
12 of the Company's RDR Plan but also a flawed understanding of the manner in which
13 capital expenditures are reflected in base rates under traditional rate making in Rhode
14 Island. Mr. Farley claims that:

15 There are ratepayer protections built into the traditional ratemaking approach.
16 One of them is that when a utility wants ratepayers to pay for capital investments,
17 the utility has the burden of proof to demonstrate with credible evidence that these
18 investments are prudent, used and useful. This revenue decoupling plans turns
19 that regulatory principle on its head. Under the Company's proposal, regulators
20 or ratepayers would have to make a case to prove that the proposed investment –
21 yet to be made – will be imprudent.⁵⁹
22

23 However, Mr. Farley's description does not reflect the Company's proposal. Under the
24 Company's Net CapEx Adjustment, net capital expenditures only become a permanent

⁵⁷ Farley Testimony, page 26.

⁵⁸ Farley Testimony, page 26.

⁵⁹ Farley Testimony, page 26.

1 part of the Company's revenue requirements (i.e., subject to final revenue adjustment and
2 reconciliation) after those actual expenditures have been reviewed by the Commission
3 and approved as prudent, used and useful.⁶⁰ The RDR Proposal does not allow for
4 ultimate recovery of any investment the Commission determines is imprudent or not used
5 or useful. There is no new burden that would be imposed on the regulator to demonstrate
6 that the Company's investments are imprudent – or prudent, for that matter. Thus, Mr.
7 Farley is factually incorrect about the operation of the Company's Net CapEx
8 Adjustment.

9
10 Further, I think that he incorrectly characterizes the Company's RDR Plan as
11 "overturning regulatory principles" as now practiced in Rhode Island. In many respects
12 (and by design by the Company), the Net CapEx Adjustment (including both the "look-
13 back" and "look-ahead" provisions) resembles the same approach that is used to establish
14 rate base for the purpose of establishing rates in a rate case. That is, this approach is
15 designed to reflect actual incremental plant additions as of the historical test year, plus
16 known and measurable changes in the following year along with estimates of 100 percent
17 of the anticipated incremental net plant addition through the 2010 rate year.⁶¹ This is

⁶⁰ The Current Year Net CapEx Adjustment is based on the net capital expenditures from the prior two years that have been approved by the Commission. Thus, just as with the development of estimates of capital expenditures for the rate year in the base rate case, revenue requirements associated with this adjustment would not reflect the actual expenditures to be made during the coming year. Further, in the event that actual capital expenditure were less than 75% of the capital expenditures from the prior two years, any additional revenue requirements collected by the Company would be refunded to customers in the following year through the reconciliation process.

⁶¹ On page 53 of his prefiled direct testimony in this proceeding, Mr. Robert O'Brien describes how the distribution plant in service for the Rate Year is determined for the Company. He describes how the "the rate year five-quarter average for distribution plant in service is calculated...beginning with the plant in service balance at December 31, 2008...The 2008 plant in service balance is increased by the plant additions for 2009 ...and decreased by the plant retirements.... The change in net plant for 2009 ... is then added to the December 31, 2008 balance which provides the balance at December 31, 2009....,The 2010 net plant additions ... equal an average monthly plant addition

1 quite similar to the Net CapEx adjustments: capital additions in the look-back portion are
2 based on actual investments since the test year, and capital additions in look-ahead
3 portion are based on 75 percent of a historical average amount. While this parallel
4 construction is not meant to “simulate the workings of a real rate case”⁶² (as suggested
5 by Mr. Farley), it is intended to reflect the same principles and comparable methodology
6 as have been used in rate cases to determine known and measureable changes in plant.
7 Rather than “turning a regulatory principle on its head,” the Company’s proposed
8 approach rests on the same foundations as investment cost recovery have been built for
9 many years in Rhode Island.

10
11 **Q. Does Mr. Farley raise similar claims about the use of forecast data that illustrate a**
12 **failure to understand the basic fundamentals of how ratemaking is performed in**
13 **Rhode Island?**

14 **A.** Yes, he does. Mr. Farley criticizes the Company’s RDR Plan because in his view, it:

15 ... uses forecasted data to predict future costs and asks the ratepayer to begin
16 paying for those projected future costs immediately. The only thing that is certain
17 about that forecast is that it will be wrong. The time-tested regulatory standard of
18 basing rates on costs that are known and measurable, with assets that are used and
19 useful, protects ratepayers. It preserves the integrity of the ratemaking process. It
20 should not be abandoned now, of all times, when the stakes in terms of our
21 economic future have never been higher, and when citizen confidence in core
22 institutions has never been lower.⁶³

23
24 But, as I note above, the Company’s RDR Plan uses the same kinds of proxies for rate

amount.... This monthly addition amount is added to the plant at December 31, 2009 ...which results in the monthly plant in service at the end of January 2010. The same procedure is used for each month in 2010 to obtain the month-end balances for each month for 2010,... The Rate Year plant in service five quarter average ...is the result of adding the balances on lines 7, 11, 14, 17 and 20 and dividing by 5....” O’Brien Testimony, page 53, lines 8-23.

⁶² Farley Testimony, page 25.

⁶³ Farley Testimony, page 27.

1 year investment levels as are used in rate case methodologies. Rhode Island
2 Commissions have established a clear precedent supporting the use of a future or
3 forecasted test year that reflects a balanced consideration of the uncertainties of reliance
4 on forecasted costs against the benefits of more complete and timely cost recovery of the
5 utility's investments. Mr. Farley grossly overstates the use of forecasted information in
6 the RDR Plan, since such "forecasts" are only used for the recovery of rate year capital
7 expenditures, are based upon actual net capital expenditures in prior year as approved by
8 the Commission, and are not, in fact, "forecasts" but proxy amounts designed to be
9 generally lower than an actual "forecast" of capital expenditures.⁶⁴ Further, any
10 differences between proxy and actual amounts would be corrected in the following year
11 through the revenue decoupling reconciliation process, so that even if actual spending is
12 below the proxy amount, ratepayers will not pay any more or less than actual, prudently
13 incurred, and used and useful capital expenditures incurred by the Company.

14
15 **Q. Is there a new benefit to customers associated with the Net CapEx Adjustment**
16 **mechanism as proposed?**

17 A. Yes. For the first time, the Company's proposal would flow dollars back to customers in
18 the event that prudent capital investment were below the amount of investment support
19 embedded in rates. This is a new customer protection and a symmetrical element of the
20 proposed Net CapEx Adjustment that shares the risks and benefits of regulatory lag and
21 more timely cost recovery signals.

⁶⁴ In this context, it is worth noting that the net plant additions are anticipated to grow from \$51.9 M in 2009 to \$65.8 M in 2010, further confirming that the 75% most likely to lead to only a partial reduction in regulatory lag. See Schedule NG-RLO-2, page 34.

1
2 **Q. Mr. Oliver concludes that the proposed Net Inflation Adjustment is “speculative**
3 **and inappropriate.”⁶⁵ Do you agree with his conclusions?**

4 A. No. The Net Inflation Adjustment provides a means for the Company’s total revenue
5 requirement to be recovered through rates to reflect economy-wide increases in key input
6 costs associated with providing service to its customers. Mr. Oliver’s concerns, however,
7 largely relate to the appropriateness of certain elements of the mechanism used in the Net
8 Inflation Adjustment. For example, he concludes that the proposed 0.5-percent
9 productivity offset, which was derived from a sample of recent empirical analysis, is
10 “little more than a judgmental estimate.”⁶⁶ In fact, my proposed offset to inflation was
11 based on a multi-step empirical analysis.⁶⁷ In the end, I used my experience and
12 judgment to propose an offset that was heavily informed by this empirical analysis.

13
14 Mr. Oliver raises two other points with respect to my analysis. First he notes that the
15 studies I consider are “an array of studies that produce substantially varying results.”⁶⁸
16 Without arguing whether the variation in study results is “large” or “small”, Mr. Oliver’s
17 apparent concern with the variation in study results highlights a strength of my empirical
18 approach: that is, that it is able to account for variation in study results through sample

⁶⁵ Oliver Testimony, page 3.

⁶⁶ Oliver Testimony, page 39.

⁶⁷ This analysis included the following steps: (1) collection of a sample of estimates of energy distribution productivity and energy distribution productivity offsets from recent empirical analyses; (2) calculation of statistical averages of energy distribution productivity and energy distribution productivity offset for the total sample of study estimates and for sub-samples of estimates based on geography and type of energy distribution; (3) development of an estimate of the productivity offset based on these statistical averages; and (4) assessment of this productivity offset for various factors that would tend to over- or under-state the true value of the productivity offset.

⁶⁸ Oliver Testimony, page 39.

1 averages, rather than relying upon one study alone. Second, Mr. Oliver suggests that my
2 analysis considers “rate settlements”⁶⁹ when, in fact, my analysis of productivity offsets
3 in Schedule NG-SFT-5 does not consider any rate settlements but only estimates of
4 energy distribution productivity and energy distribution productivity offsets developed
5 through empirical analysis. Thus, this concern is factually incorrect.

6
7 Mr. Oliver also raises concerns that my recommended use of the Gross Domestic Product
8 Price Index (“GDP-PI”) as the index for the inflation adjustment does “not necessarily
9 provide a reasonable or accurate depiction of the distribution O&M cost increases for
10 National Grid’s Rhode Island Operations.”⁷⁰ He also raises concerns about differences
11 between industry-specific costs and those measured by the GDP-PI, stating: “no
12 demonstration has been made that the mix of items used to compute price changes for the
13 GDPPI is in any way analogous to the mix of products and services that comprise the
14 Company’s costs.”⁷¹ In fact, my suggested 0.5-percent offset is intended to account for
15 differences that may exist between both regional-specific and industry-specific market
16 conditions and factors those reflected in economy-wide price measures such as the GDP-
17 PI. However, the mechanism for accounting for these differences is embedded in the
18 measurement of the productivity offset itself. Thus, Mr. Oliver’s concerns appear to arise
19 from a misunderstanding of the fundamentals of how inflation indexes are constructed.
20 In particular, he appears unaware of the fact that (1) the productivity offset is designed to
21 account for differences between economy-wide measures of inflation and industry-

⁶⁹ Oliver Testimony, page 39.

⁷⁰ Oliver Testimony, page 39.

⁷¹ Oliver Testimony, page 43.

1 specific productivity and costs;⁷² and (2) differences between economy-wide and regional
2 market conditions can be captured by estimating the productivity offset using region
3 specific data, as was done in five of the seven studies assessed in Schedule NG-SFT-5.
4 Thus, despite Mr. Oliver's claims, my estimates of the productivity offset do account for
5 differences between economy-wide prices and those faced by regional energy distribution
6 companies.

7
8 Finally, his very criticism of my proposal to use an inflation index tied to Gross Domestic
9 Product seems odd in light of allowed practice in Rhode Island to include an inflation
10 adjustment based on such indices as an element of calculating the rate year revenue
11 requirement in rate case proceedings. Again, the attempt was to use a metric well-known
12 to the Commission and then to adjust it (i.e., with the 0.5-percent offset) to address
13 differences between economy-wide inflation and industry- and region-specific changes.

14
15 **Q. Does Mr. Oliver also raise concerns with quality of the underlying studies used in**
16 **your analysis of productivity offsets?**

17 A. Yes he does, although his concerns are largely conjecture without any substantive or
18 empirical support. He states that "production of reliable estimates of the productivity
19 offsets that can reasonably be expected from real world utility operations given rapidly
20 changing economic, regulatory, and market conditions is an undertaking of questionable
21 merit. The fact that analysts can manipulate data and compute estimates does not make

⁷² Footnote 65 of my direct testimony provides a formula for the productivity offset, which shows how it is designed to account for the differences in the growth between: (1) industry-specific productivity and economy-wide level productivity; and (2) industry-specific input costs and economy-wide input costs.

1 those estimates reasonable or reliable.”⁷³ However, Mr. Oliver provides not a single
2 analysis, study, or even anecdotal observation to support his apparent concern with the
3 quality of empirical analyses of industry productivity. In fact, a substantial applied
4 economic and regulatory literature has developed around the issue of the development of
5 reliable estimates of the productivity offsets,⁷⁴ and these estimates have been relied upon
6 by many regulatory commissions in the development of performance based regulatory
7 plans and in the other regulatory determinations.⁷⁵ Again, I recommend that the
8 Commission place no weight on Mr. Oliver’s comments.
9

10 **Q. Mr. Oliver assesses the trends in energy distribution productivity.⁷⁶ Do you have**
11 **any comment on his findings?**

12 A. In his testimony, Mr. Oliver’s points to one study that indicates that energy distribution
13 productivity has fallen from the mid 1990’s to more recent periods. I note that if industry
14 productivity were declining over time that my proposed productivity offset would tend to
15 overstate the true level of the productivity offset and therefore lead to smaller
16 adjustments in rates. In this context, it is also worth noting that the Company has been
17 subject to some form of a rate cap or rate plan in Rhode Island since the last general rate

⁷³ Oliver Testimony, page 40.

⁷⁴ For example, see Jeffrey Bernstein and David Sappington, “Setting the X Factor in Price Cap Regulation Plans,” *Journal of Regulatory Economics*, July, 1999; Mark N. Lowry, and Lullit Getachew, “Price Control Regulation in North America: Role of Indexing and Benchmarking,” *The Electricity Journal*, January/February 2009.,

⁷⁵ See Schedules NG-SFT-4 and NG-SFT-5. Also, David Sappington, Johannes Pfeifenberger, Philip Hanser, and Gregory Basheda, “The State of Performance-Based Regulation in the U.S. Electric Utility Industry,” *Electricity Journal*, October 2001.

⁷⁶ Oliver Testimony, pages 40-43.

1 case in 1995;⁷⁷ as such, these rates have provided the Company with incentives to achieve
2 improvements in the efficiency and productivity of its operations. Having faced this
3 incentive for this period of time, the Company may have captured many of the easier
4 opportunities to increase productivity, which would suggest that further improvements
5 may be more difficult to come by in the future. I also note that Mr. Oliver has absolutely
6 no basis for suggesting that the increase in the productivity offset in the initial years of
7 the NSTAR performance-based rate plan was influenced in any way by empirical
8 changes in productivity over that period as opposed to the many other interests particular
9 to NSTAR and that could have contributed to that settlement outcome.⁷⁸

10
11 **Q. Mr. Farley suggests that, with implementation of the RDR Plan, ratepayers would**
12 **no longer “reap the benefits” of actions taken by utility management to lower costs.**
13 **Do you agree with this conclusion?**

14 A. No. In fact, the proposed Net Inflation Adjustment will provide ratepayers with the
15 benefit of the costs savings achieved by management’s efforts to improve productivity as
16 they “adjust their financing strategy, they aggressively manage costs.”⁷⁹ This savings is
17 achieved through the 0.5-percent productivity offset, which reduces the annual
18 adjustments in operations and maintenance costs to account for changes in productivity of
19 operations (along with change in the cost of inputs). Under the Net Inflation Adjustment,
20 if the Company fails to achieve the improvements in productivity at levels equal to
21 industry averages, its expenditures for operations and maintenance will most likely grow

⁷⁷ Prefiled Direct Testimony of Tom King, page 16.

⁷⁸ Oliver Testimony, pages 41.

⁷⁹ Farley Testimony, page 26.

1 at a faster rate than its revenue collections to cover such costs. Therefore, customers
2 clearly “reap the benefits” of actions taken by utility managers to lower costs under the
3 Company’s RDR Plan.

4
5 **Q. Mr. Oliver identifies deficiencies in the Company’s filing, noting that “calculations**
6 **necessary to implement the Company’s proposed Net CapEx Adjustments to its**
7 **Annual Target Revenue (“ATR”) are not sufficiently detailed in the Company’s**
8 **proposed tariff to facilitate regulatory oversight and ensure proper computation.”⁸⁰**
9 **What are your views on the adequacy of the documentation of methods and**
10 **calculations needed to perform rate adjustments under the RDR Plan?**

11 A. I disagree with Mr. Oliver that the Company’s filing does not provide adequate
12 documentation of the calculations necessary to implement the RDR Plan. Descriptions of
13 the calculations required to implement annual adjustments are clearly laid out in (1) my
14 direct testimony, (2) Schedule NG-RLO-7 of Mr. O’Brien’s direct testimony, and (3) the
15 proposed tariffs included in Mr. Gorman’s testimony as Schedule NG-HSG-11. The
16 tariffs provide detail comparable to the adjustment mechanisms previously approved by
17 the Commission for costs such as Transmission Service and Transition Charge.

18
19 Mr. Oliver identifies two particular amendments to the tariff language. First, he suggests
20 that the tariffs should explicitly state that interest would be applied to any deferred
21 revenue balances or deficits arising from the RDM reconciliation.⁸¹ Second, he suggests

⁸⁰ Oliver Testimony, page 4.

⁸¹ Oliver Testimony, page 55.

1 that the tariffs explicitly state that reconciliations and interest computations be calculated
2 monthly.⁸² Both of these suggestions are relatively minor and easily addressed by the
3 Company in revisions to its proposed tariffs, should the Commission adopt his
4 recommendations.

5
6 **Q. Mr. Oliver concludes that the proposed Net Inflation Adjustment is “speculative**
7 **and inappropriate.”⁸³ Do you agree with his conclusions?**

8 A. No. The Net Inflation Adjustment provides a means for the Company’s total revenue
9 requirement to be recovered through rates to reflect increases in the Company’s costs for
10 obtaining labor, materials and services used in providing service to its customers. As an
11 important complement to revenue decoupling, it is a necessary element of the ability of
12 the RDR Plans to support reductions in ratepayer’s total bills by reducing their payments
13 for commodity, transmission and distribution services.

14
15 **Q. Mr. Oliver indicates that you “assert[] that revenue decoupling will reduce rate**
16 **volatility.”⁸⁴ Is this your view on the relationship between revenue decoupling and**
17 **rate volatility?**

18 A. No. As I stated clearly in footnote 37 of my direct testimony, “Revenue decoupling of
19 distribution rates will generally tend to have a small, and potentially positive or negative,
20 impact on the volatility of customer’s total electricity bills. Thus, it will have no
21 appreciable impacts on customer risk.” The same can potentially be said for rates, as

⁸² Oliver Testimony, page 55-56.

⁸³ Oliver Testimony, page 3.

⁸⁴ Oliver Testimony, page 23.

1 well as total bills, although any conclusion would depend on the particular circumstances
2 of the utility implementing decoupling, including its ratemaking structure. More
3 importantly, my testimony highlighted that any increased volatility in rates that could
4 potentially arise from decoupling would be swamped by the volatility in the commodity
5 prices faced by customers. Thus, while decoupling has no appreciable effect on the
6 volatility of customer's total bills, the more aggressive pursuit of energy efficiency
7 enabled by revenue decoupling would provide customer benefits not only through
8 reduction in commodity payments but also reduced exposure to the risks of volatile
9 commodity prices.

10
11 Figure NG-SFT-6 illustrated the dramatic difference between volatility in commodity
12 rates and volatility of distribution rates under a revenue decoupling mechanism. The
13 illustration was made by comparing monthly billings for a customer over the period 2001
14 to 2008 assuming: (1) fixed monthly energy use, (2) commodity charges based on *actual*
15 Standard Offer commodity rates; and (3) distribution rate under a hypothetical
16 decoupling mechanism, in which the distribution rate is calculated based on a 2002 test
17 year *actual* revenues, and *actual* energy use and *actual* revenues in each year.

18
19 Mr. Oliver offers certain comments on Figure NG-SFT-6, although his comments only
20 confuse the underlying issues, in my view, since they reflect an apparent
21 misunderstanding of my methodological approach and assumptions. First, he suggests
22 that the figure is designed to show that "monthly billings for a residential customer billed

1 under rate A-16 would have been nearly flat over that period.”⁸⁵ This is clearly not the
2 intent of Figure NG-SFT-6, and inconsistent with commentary on this figure in my direct
3 testimony – for example,: “All in all, the changes in distribution rates that would arise
4 from a revenue decoupling mechanism to reconcile allowed distribution revenue to actual
5 would be swamped by the type of variation seen historically in commodity charges.”⁸⁶
6

7 Second, Mr. Oliver concludes that “no variations in usage were allowed to affect the
8 Company’s estimated residential billings with an RDM in place for the years 2003-2008.
9 Naturally, if the analysis is structured in a manner that assumes away variations in usage,
10 year-to-year impacts on customer bills may appear small.”⁸⁷ However, as clearly
11 explained in my direct testimony and above, Mr. Oliver is simply incorrect about the
12 assumptions used in developing Figure NG-SFT-6. Thus, Mr. Oliver’s concerns, based
13 on an unfounded assumption about my analysis, are without foundation, only serve to
14 confuse the underlying issues, and should be ignored.
15

16 **Q. Mr. Kahal comments that the proxy group of seven electric companies used by Mr.**
17 **Paul Moul to assist in developing his recommended return on equity is a set with**
18 **ratemaking mechanisms “does not fully comport with the Company’s proposal.”⁸⁸**
19 **Do you agree with his observation?**

20 **A.** No. I have reviewed the revenue decoupling and other ratemaking elements of the seven

⁸⁵ Oliver Testimony, page 25.

⁸⁶ Tierney Direct Testimony, pages 42.

⁸⁷ Oliver Testimony, page 25.

⁸⁸ Prefiled Direct Testimony of Matthew Kahal, page 51.

1 electric companies used as a proxy group by Mr. Moul. The seven companies are:
2 Consolidated Edison, Edison International, Idacorp Inc., PEPCO Holdings, PG&E
3 Corporation, Portland General, and Sempra Energy, As Mr. Moul explained in Schedule
4 NG-PRM-3 (page 2), he based his selection of the proxy group by identifying a set of
5 “publicly-traded companies that are included in The Value Line Investment Survey, (i)
6 are currently paying a dividend on their common stock, (ii) are not presently the target of
7 an announced acquisition or merger, (iii) have at least 60% of their identifiable assets
8 devoted to utility regulation, (iv) currently have a revenue decoupling mechanism
9 (“RDM”) in effect, and (v) have a bond rating of BBB/Baa2 or above.” As such, this
10 group was based on other selection criteria besides the fact that the companies had a
11 revenue decoupling mechanism in place. Even so, and in response to Mr. Kahal’s point,
12 this group includes many companies with companion ratemaking adjustments in addition
13 to revenue decoupling. The combined ratemaking approaches are quite similar to if not
14 exactly the same ratemaking adjustments that complement revenue decoupling in the
15 Company’s proposed RDR Plan. Schedule NG-SFT-3 of my direct testimony illustrated
16 that many of the utilities in Mr. Moul’s samples have ratemaking elements designed to
17 make annual adjustments to total revenue requirements given actual or anticipated
18 changes in capital expenditures and operations costs.⁸⁹ These adjustments include
19 adjustments to target revenues for capital investment, adjustments for operations and
20 maintenance costs (including indexed inflation adjustments), and adjustments for other
21 elements of the utility’s cost structure. For example, the three California utilities (PG&E,
22 Edison International’s Southern California Edison (“SCE”), and Sempra’s San Diego Gas

⁸⁹ See also the company-specific descriptions in the Lesh Report.

1 & Electric Company (“SDG&E”) all have mechanisms (e.g., so-called “attrition”
2 adjustments) that adjust target revenues after the rate case. Some of the companies
3 (PEPCO Holdings’ PEPCO and Delmarva Power; Idacorp’s Idaho Power; ConEd) have
4 ratemaking elements that reconcile and adjust their revenues more frequently (e.g.,
5 monthly, semi-annually) than annually, as proposed by the Company. These
6 considerations, in addition to those identified by Mr. Moul, support the view that this
7 proxy group has overall risk-related attributes (including their ratemaking mechanisms)
8 that are reasonably comparable to those being proposed by the Company in this
9 proceeding. That is not to say that each company’s package of ratemaking elements is
10 exactly the same as each other’s or as the Company’s proposed RDR Plan, but they do
11 include mechanisms that allow for adjustments to annual target revenues for the purpose
12 of reconciling actual to target revenues under revenue decoupling.

14 **VI. Response to Intervenor Witnesses’ Proposed Modifications and/or**
15 **Recommendations Relating to the Company’s Proposed RDR Plan**

16 **Q. Please provide your overall response to the recommendations of Mr. Farley and Mr.**
17 **Oliver,⁹⁰ that the Commission reject the Company’s proposed RDR Plan.**

18 **A.** I disagree with this recommendation, for the reasons stated above and in my original
19 prefiled direct testimony. For these reasons, and for the many similar reasons suggested
20 by Ms. Cleveland and Dr. Lowry, I urge the Commission to adopt the Company’s
21 proposed revenue decoupling plan, with its companion Net CapEx Adjustment and Net
22 Inflation Adjustment mechanisms.

⁹⁰ Oliver Testimony, page 8; Farley Testimony, page 23.

1 **Q. What is your view of Mr. Oliver's recommendations regarding revenue decoupling**
2 **components, in the event that the Commission decided to adopt it for the Company?**

3 A. Mr. Oliver recommends a number of modifications to the revenue decoupling
4 mechanism, should the Commission decide to implement it in this proceeding. I'll
5 address each one separately.

6
7 First, he suggests that there be no adjustments to target revenues for capital investments
8 or net inflation, and that revenue decoupling be limited to reconciliation of actual and
9 approved revenue requirements from the rate case.⁹¹ I encourage the Commission to
10 dismiss this recommendation. As I have described above, the combined effects of
11 regulatory lag, increased distribution investment costs, rising operating costs, and
12 diminished opportunity to use sales growth to provide revenue additions to fund increases
13 in operating costs all converge to put enormous pressure on the ability of the Company to
14 provide high-quality service to customers, assist them in managing their own high energy
15 costs through energy efficiency, and have a genuine chance of earning the rate of return
16 on equity that the Commission allows in this proceeding. As shown in Figure NG-SFT-
17 R-1, if the Commission decides to adopt revenue decoupling without the companion
18 ratemaking mechanisms proposed in the RDR Plan package and if the anticipated level of
19 capital additions is determined to be needed to provide economical and reliable service to
20 customers, there is a virtual certainty that the Commission will be introducing more
21 frequent, and potentially even annual or bi-annual rate case proceedings. Including the
22 proposed mechanisms provides a reasonable balance of administrative efficiency,

⁹¹ Oliver Testimony, page 8.

1 regulatory oversight, assurance of service quality, and a reasonable opportunity to earn
2 allowed rates of return.

3
4 Second, in the event that the Commission adopts revenue decoupling, Mr. Oliver
5 recommends that there be a hard, *a priori* cap on the amount of revenue that may be
6 reconciled in any period set equal to positive or negative 10 percent of the Company's
7 base revenue requirement for each rate class.⁹² I strongly encourage the Commission not
8 to adopt his proposed cap. A proposal to cap the amount of revenues that could be
9 reconciled would constitute a denial of revenues determined by the Department to be just
10 and reasonable, and unfair to both customers and the Company. The existence of a hard
11 cap on revenues allowed to be reconciled in any period is one of the factors viewed as
12 contributing to problems in Maine's past experience with revenue decoupling.⁹³ The
13 purpose of the Company's proposal to provide notice to the Commission in the event of

⁹² Oliver Testimony, page 29.

⁹³ There are many factors that distinguish revenue decoupling in the Company's case from the experience of Central Maine Power ("CMP") during the early 1980s. These reasons include: CMP was vertically integrated (owning generation, transmission, and distribution assets); its revenue decoupling incorporated revenues for all of those functions except the fuel portion of generation costs and therefore involved most of the costs reflected in retail customers' bills; there was a limitation on the amount of revenue that could be reconciled in any time period; that fact, timed with an economic downturn with substantially lower kWh sales (including significant reductions in industrial sales), caused large amounts of revenues that needed to be reconciled but which had to be accrued in an account in light of the cap on reconcilable dollars in any period; an accounting ruling that would have caused such accrued revenues to be lost if not passed through in a short-term period; and CMP's energy efficiency programs not being viewed as sufficiently aggressive. The CMP plan was ultimately dropped. Many other observers (including the staff of the National Association of Regulatory Utility Commissioners ("NARUC"), discussed below) have explained why the Maine experience should be viewed as an isolated problem. In fact, one of the very acute problems in Maine, in fact, arose from the limitation on the amount of total revenue that could be reconciled in any period – something that Mr. Oliver proposes to impose on the Company's RDR Plan as well. I urge the Department to recognize the many differences in circumstances that distinguish the Maine experience during the 1980s with today's experience in Massachusetts.

According to a "revenue decoupling" fact sheet prepared by the NARUC staff, "Maine's decoupling experience... It should be noted that while decoupling is often cited as the culprit here, in fact the economic downturn was the problem. Traditional regulation would have eventually yielded rate changes through a traditional rate case and the resulting price increases would have reflected the same economic circumstances." NARUC Grants & Research Department, "Decoupling For Electric & Gas Utilities: Frequently Asked Questions (FAQ)," 2007.

1 an accumulating balance of positive or negative 10 percent is to give the Commission the
2 flexibility to determine how to address such a situation.

3
4 Third, Mr. Oliver suggests that in the event that the Commission adopts revenue
5 decoupling, there should be adjustments to exclude any revenues lost as a result of major
6 electrical outages and out-of-period billing adjustments.⁹⁴ Implementation of both of
7 these recommendations would add unnecessary complications to annual adjustments for
8 little gain. He argues that excluding revenues lost from major electrical outages will
9 provide management with better incentives to reduce outage lengths. While management
10 has some control over outage lengths, storm severity, a factor well beyond the
11 Company's control, is clearly the most significant factor in determining the length of
12 these outages. Further, to ensure that the Company has an opportunity to achieve full
13 recovery of its approved revenue requirement, Mr. Oliver's suggestion would require
14 design of a mechanism to measure lost outage revenues relative to some benchmark level
15 or else the Company would never collect its allowed revenue requirement any time there
16 were any storm-related lost revenues. Likewise, implementation of measures to account
17 for and track out-of-period billing adjustments would add unnecessary complications to
18 annual adjustments with little gain. In light of these considerations, I am not surprised
19 that I have not heard of any utilities that have annual adjustments that account for either
20 lost storm-related revenues or out-of-period billing adjustments. I recommend that
21 Commission approve the Company's RDR plan without either of these proposed
22 adjustments.

⁹⁴ Oliver Testimony, pages 33, 35-36

1 Fourth, Mr. Oliver recommends that the approved return on common equity “should be
2 lowered to reflect the impacts of such a mechanism on the Company’s risk profile and
3 return requirements, as recommended by Division witness Kahal.”⁹⁵ However, as
4 discussed above, any potential impact that revenue decoupling has on the financial risks
5 faced by the Company and its resulting return of equity has already been accounted for in
6 Mr. Moul’s analysis which is based on a proxy group of companies with revenue
7 decoupling. Because Mr. Moul’s analysis already accounts for these effects, a separate
8 adjustment for presumed affects of revenue decoupling on the Company’s appropriate
9 return on equity would be double counting.⁹⁶ Thus, the Commission should ignore Mr.
10 Oliver’s recommendation.

11
12 Finally, I do agree with Mr. Oliver on one point. He indicates that the Net CapEx filings
13 should “include sufficient information to support Commission findings regarding the
14 “*prudent, used and useful*” nature of each capital addition to be included in rates, not just
15 a list of the capital additions and their costs.”⁹⁷ I agree with Mr. Oliver that the
16 Company’s filings should include sufficient information for the Commission to determine
17 whether capital expenditures proposed for recovery through rates are “prudent, used and
18 useful,” and that the standards used to assess the appropriateness of the Company’s
19 twice-annual filings should be no different than the standards for such filings in a full rate

⁹⁵ Oliver Testimony, page 9.

⁹⁶ As I said in my prefiled direct testimony, “In fact, I would expect that if the Commission decided not to adopt revenue decoupling in this case, it would also be consistent for the Commission then to adjust upward the cost of capital proposed by Mr. Moul, since it reflects the assumption that revenue decoupling will be in place for the Company when new rates go into effect.” Tierney direct testimony, page 45.

⁹⁷ Oliver Testimony, page 47.

1 case. In fact, the Company's proposal was designed to provide the Commission with
2 greater opportunity to review such information on capital expenditures through annual
3 filings, rather than infrequent filings that require review of multiple years of capital
4 expenditures. Further, the Company's proposal is designed so that annual Net CapEx
5 adjustments would only reflect capital expenditures that have been approval by the
6 Commission as "prudent, use and useful".
7

8 **VII. Conclusion**

9 **Q. Does this conclude your testimony?**

10 **A.** Yes it does.

Schedule NG-SFT-R-1

**Regulatory Assistance Project, Issuesletter, September 2009: The Role of
Decoupling Where Energy Efficiency Is Required by Law**

Regulatory Assistance Project Issuesletter

September 2009

THE ROLE OF DECOUPLING WHERE ENERGY EFFICIENCY IS REQUIRED BY LAW

The American Council for an Energy-Efficient Economy (ACEEE) reports that 19 US states have adopted an Energy Efficiency Resource Standard (EERS) requiring achievement of specified energy saving targets.¹ A comprehensive energy bill pending in the 111th Congress includes a combined efficiency and renewable electricity standard that would allow electricity savings to meet at least one-quarter of the requirement.² A more targeted proposal calls for a federal EERS that would require distribution utilities to achieve electricity savings of 15 percent and natural gas savings of 10 percent by 2020 (see table).³

Principal author
Lisa Schwartz

Such standards, or broader requirements to acquire all cost-effective energy efficiency, raise the question of whether decoupling of utility profits from utility sales still has a role in meeting state and federal goals for efficiency and other clean energy sources. This *Issuesletter* explains why aggressive standards make it even more urgent that state Commissions reject structural conflict in traditional regulation that frustrates the least-cost, least-risk path to a low-carbon future. Without decoupling – that is, under traditional ratemaking – utilities are

told to do one thing (promote energy efficiency) while they typically make more money when they do the opposite (increase sales).

Energy Efficiency Resource Standards

An EERS is similar in concept to a renewable energy standard. It requires the state or utility to achieve specified levels of energy savings. Savings targets typically are expressed as a percentage reduction relative to retail energy sales during a baseline period – for example, average sales during a prior two-year period.⁴ These savings are generally achieved through efficiency programs for end-use customers. Savings from building codes, appliance efficiency standards, combined heat and power facilities, and distribution system efficiency improvements also may count toward meeting the standard.

If the jurisdiction adopts a cumulative savings objective – say, 15 percent electricity savings by 2020 – annual targets will typically increase over time to reflect the continued impacts of measures installed each year. With a cumulative target, the lifetime savings associated with installation of energy efficiency measures are counted. Thus program administrators are fully credited for installing long-lived and well-maintained measures. Yearly

Proposed Federal EERS⁵

Sector	Electricity		Natural Gas	
	Annual Savings	Cumulative Savings	Annual Savings	Cumulative Savings
Year				
2011	0.33%	0.33%	0.25%	0.25%
2012	0.67%	1.00%	0.50%	0.75%
2013	1.00%	2.00%	0.75%	1.50%
2014	1.25%	3.25%	1.00%	2.50%
2015	1.25%	4.50%	1.00%	3.50%
2016	1.50%	6.00%	1.25%	4.75%
2017	1.50%	7.50%	1.25%	6.00%
2018	2.50%	10.00%	1.25%	7.25%
2019	2.50%	12.50%	1.25%	8.50%
2020	2.50%	15.00%	1.50%	10.00%

savings targets provide short-term goals and a yardstick for monitoring progress.

An EERS is a performance-based approach that, once established, removes the need to continually address funding levels for energy efficiency – at least for a while. An EERS may allow an alternative compliance payment in lieu of meeting the standard, with the money directed to a state agency charged with achieving the intended savings. A penalty may be assessed for falling short of the requirements. Where the obligation falls on the utility, the law may allow the trading of savings with other utilities as well as contracting with energy service companies or a state agency to administer programs to meet the standard.

Many jurisdictions outside the US have implemented mechanisms similar to an EERS. The longest running of these is in the United Kingdom. Beginning in 1994, the Energy Efficiency Standards of Performance required electricity suppliers (retailers) to spend £1 per residential customer on household energy-saving measures and set energy savings targets to be achieved by the suppliers.⁶ In 2000, the program was extended to all electricity and gas suppliers with at least 50,000 customers, becoming the dominant energy efficiency vehicle for residential customers in the UK. In 2002, the program was renamed the Energy Efficiency Commitment with a new focus on reducing greenhouse gas emissions. However, supplier targets were still expressed in terms of energy savings. Now known as the Carbon Emissions Reduction Target, it is the main policy instrument in the UK for reducing carbon emissions from existing homes. Under the program, electricity and gas suppliers must meet specified carbon emissions reductions.⁷

In Australia, New South Wales, Victoria, and South Australia have imposed what are in effect energy efficiency resource standards. These take the form of obligations imposed on electricity retailers, expressed as reductions in greenhouse gas emissions from electricity sold.⁸ Specified energy efficiency measures in the residential sector are deemed to achieve set levels of emissions reduction. In New South Wales and Victoria, the emissions reduction obligation is linked to a trading scheme for energy efficiency certificates.⁹

Energy Efficiency Potential and Cost

ACEEE cites a median level of cost-effective, achievable potential for electric savings in the US of 18 percent.^{10,11} That means currently available technologies and approaches can reduce by 18 percent the amount of electricity needed to provide the same level of service. The potential for natural gas savings also is large. The American Gas Association reports that annual energy savings of member utility efficiency programs averaged nine percent of usage for residential participants and seven percent for all participants in 2007.¹² Similarly, ACEEE reports savings from Vermont Gas programs from 1999 to 2006 at 7.8 percent of 2006 sales, and Iowa gas utility programs from 1996 to 2006 at 8.2 percent of 2006 sales.¹³

Not only is there a vast potential remaining to be tapped, but energy efficiency also costs far less than supply-side alternatives. The National Action Plan for Energy Efficiency (NAPEE) cites “conservatively high estimates” for the total (utility and participant) cost of efficiency programs at 4 cents per kilowatt-hour (kWh) for electricity measures and \$3 per million British thermal units (MMBtu) for natural gas measures.¹⁴ ACEEE reports preliminary research results indicating average program costs of about 3 cents per kWh saved and 29 cents per therm saved (\$2.90 per MMBtu).¹⁵

Compare that to the cost of a new natural gas-fired, combined-cycle combustion turbine. One recent forecast put the real-levelized cost at 8 cents per kWh (2006 dollars), including transmission.^{16,17} The same forecast projects natural gas prices for the period 2010 to 2029 at about \$8 per MMBtu (2006 dollars).¹⁸ These price estimates do not reflect distribution costs, reserves, line losses, or potential regulatory costs for greenhouse gas emissions.

Given the tremendous potential of energy efficiency, its cost compared to supply-side alternatives, and its zero-carbon footprint,¹⁹

states should do all they can to remove regulatory barriers that stand in the way of accelerating its acquisition – with or without an EERS.

Decoupling Basics

Most utility costs do not change immediately in response to changes in energy consumption. In the short run, capital costs for generation, transmission, and distribution, as well as expenses for meter reading, billing, customer service, and administration, are largely fixed. However, like most businesses, utilities recover a large amount of their fixed costs through volumetric rates. Because so many of the costs of providing service do not change in the short run, a one percent change in sales can result in a disproportionately larger change in utility earnings, on the order of 10 percent or more.^{20,21} That's a powerful disincentive to embracing energy efficiency and, conversely, a very strong reason to increase sales.

Decoupling breaks the link between how much energy a utility sells and the revenue it collects to cover fixed costs.²² Fundamentally, decoupling eliminates a utility's incentive to encourage consumers to increase energy use in order to increase profits as well as its disincentive to promote energy efficiency.

Decoupling is often viewed as a significant deviation from traditional regulatory practice. In fact, it is only a slight modification. The difference is straightforward.

In a rate case, the Commission sets the amount of revenue a utility ought to collect if it experiences the assumed financial, business, and sales conditions. The utility's "revenue requirement" is the sum of its expected expenses, return of – and return on – investment, and taxes, all during the test year used in the case. In theory, the amount collected should be sufficient to cover the utility's cost of service – no more, no less.

Under traditional regulation, the revenue requirement is used only to set prices (revenue requirement ÷ unit sales during the test period). Actual revenue and profit are a function of actual sales and expenses (actual profit = actual sales - actual expenses), which, in reality, have no relationship to the allowed revenue or rate of return in the rate case.

A utility can increase profits two ways under traditional regulation: (1) reduce expenses and (2) increase sales (units sold). It's easier to increase sales, which in turn increases revenue and profit. This is the heart of the throughput incentive, and it's where decoupling comes in.

Under decoupling, the rate case process remains the same. However, the prices computed in the case are in place for an initial period²³ and thereafter are relevant only as a reference point. Prices are adjusted periodically to keep revenue at its allowed level,²⁴ reflecting differences between the forecasted units sold (in the rate case) and actual units sold. In other words, decoupling fixes the revenue the utility collects and lets prices float up or down with actual sales. If sales increase, prices fall. If sales decrease, prices rise. That's in contrast to traditional regulation which fixes prices between rate cases and lets revenue float up or down with actual sales. A recent study found that decoupling price adjustments for electric and natural gas utilities tend to be small – typically under two percent of the total retail rate, positive or negative, with the majority under one percent.²⁵

Decoupling often is considered when introducing or expanding energy efficiency efforts, but it also is desirable outside that context. That's because, under decoupling, the only way a utility can increase its profits is by reducing costs. A strong incentive to manage costs efficiently is especially welcome today, with ratepayers facing mounting pressure on

near-term rates as utilities transition to low-carbon energy sources, advanced metering, and distribution and transmission system upgrades – all of which should ultimately reduce consumer bills.

Commissions also should consider adopting or strengthening service quality standards in tandem with decoupling, to ensure that service is maintained at current or improved levels. Such standards include metrics against which utility performance will be evaluated, financial penalties for failure to meet the standards, and public reporting requirements. Among the measures to consider are at-fault customer complaints, billing accuracy, power interruptions, safety violations, vegetative management, and inspections and maintenance.

EERS and Decoupling

Under traditional price-setting regulation, a utility with a legal mandate to acquire energy efficiency²⁶ feels the financial pinch of reduced sales just as it would without such an aggressive requirement, only more sharply. At the same time, the utility will still have the incentive to increase sales in order to increase profits.

That structural conflict is at best paradoxical. At worst, it makes utilities adversaries instead of motivated partners in the myriad of venues where energy efficiency goals and activities are hammered out, including:²⁷

- State and federal processes to improve building codes and appliance standards
- Customer contacts and referrals
- Consumer education
- Customer-specific²⁸ and aggregate information for third-party program administrators and service providers

Furthermore, the same throughput incentive that deters utilities from making energy efficiency investments also dissuades them from supporting distributed generation and demand response, both of which also can

decrease sales.

These conflicts play out within the utility, too. Personnel promoting customer-sited resource programs run up against financial staff stymieing their efforts. When visible, regulators are left to sort out the mixed signals – a frustrating experience in uncovering the facts. Such counteraction also sends confusing messages to consumers and the efficiency marketplace, potentially wasting efficiency funds and momentum.

The stress intensifies under an EERS, with annual savings requirements of, say, two percent of prior period sales. Such requirements do not correct the fundamental problem of a utility business model that is incompatible with reducing energy sales. A utility in this situation will simply have another perverse incentive – to work hard to make it look like the targets are reached, but not necessarily to achieve the actual savings required. That includes “gaming” sales forecasts – as well as savings estimates – in every proceeding that establishes base rates. Absent decoupling, utilities are motivated (only by fear of penalty) to do the bare minimum to meet the standards, regardless of the savings potential or benefits to consumers from exceeding the standards.

Does Third-Party Administration Solve the Problem?

Third-party administration of energy efficiency programs is one tool US states are using to address the utility throughput incentive.²⁹ Funds collected through a system benefits charge are turned over to an organization whose mission is to acquire energy efficiency on behalf of ratepayers.³⁰ Programs may serve only customers of the regulated utilities or customers of consumer-owned utilities, as well. Similar programs outside the US use a simple levy on electric utility sales revenue to establish a fund which finances measures implemented by third parties. Often there is a

competitive process for allocating the funds.

The third-party model reduces the ability, but not the incentive, for utilities to act on their inherent bias against a reduction in sales. Because under this model the utility does not even face the conflict presented by energy efficiency, it can instead respond solely and fully to the throughput incentive.

US states that have adopted third-party administration, including Oregon, Vermont, and Wisconsin,³¹ are places to look for evidence of the continued need for decoupling. In fact, commissions in these states still find decoupling a necessary tool to meet energy efficiency goals. The Oregon Public Utility Commission explained its rationale in a recent ruling approving decoupling for the largest utility in the state, Portland General Electric (PGE):

[W]hile the parties do not disagree that relying on volumetric charges to recover fixed costs creates a disincentive to promote energy efficiency, they contend that decoupling is unnecessary because, with the ETO running energy efficiency programs in PGE's service territory, the Company has limited influence over customers' energy efficiency decisions. We find this position unpersuasive, because PGE does have the ability to influence individual customers through direct contacts and referrals to the ETO. PGE is also able to affect usage in other ways, including how aggressively it pursues distributed generation and on-site solar installations; whether it supports improvements to building codes; or whether it provides timely, useful information to customers on energy efficiency programs. We expect energy efficiency and on-site power generation will have an increasing role in meeting energy needs, underscoring the need for appropriate incentives for PGE.³²

Similarly, the Vermont Public Service Board has approved decoupling for Green Mountain Power³³ and Central Vermont Public Service (CVPS).³⁴ And the Wisconsin Public Service Commission recently approved decoupling for Wisconsin Public Service Corporation.³⁵

A third-party provider operates most effectively when it works with the utility, has access to the utility's cost, usage, and demand data, coordinates projects to reduce load on the distribution circuits that face upgrade costs if load grows, and presents itself to customers as a partner with the utility. Without decoupling, the utility has an incentive not to work with the third-party provider.

Another factor elevates the need for decoupling in these states: Utilities can request approval from the state commission to include in base rates funding for energy efficiency that is incremental to the amount that can be acquired through the system benefits charge. Therefore, the utility still has significant control over the funding level, regardless of whether a third-party administrator runs the efficiency programs.

Clearing the Path to High Efficiency

Mounting evidence that efficiency is the least-cost, least-risk energy resource is leading to increasingly aggressive savings requirements. Climate change mitigation strategies compound this trend. However, neither requirements in law nor third-party administration of programs negate efficiency's fundamental conflict with the traditional utility business model, where earnings fall disproportionately with declining energy sales. Decoupling, which eliminates the conflict, is therefore a key policy tool for achieving high levels of energy savings through performance standards like an EERS as well as traditional utility programs, building codes, equipment standards, and consumer education. 

¹ California, Colorado, Connecticut, Hawaii, Illinois, Iowa, Maryland, Michigan, Minnesota, Nevada, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Vermont, Virginia, and Washington. In addition to strict EERS requirements, ACEEE includes states with Commission-ordered efficiency targets, states that allow efficiency to count toward renewable energy standards, and states with a rate cap triggering a relaxation of EERS requirements. See Laura A. Furrey, Steven Nadel, and John A. "Skip" Laitner, ACEEE, *Laying the Foundation for Implementing a Federal Energy Efficiency Resource Standard*, March 2009, at <http://aceee.org/pubs/e091.htm>.

² The proposed standard in H.R. 2454 starts at six percent of sales in 2012 and rises to 20 percent of sales in 2020. State governors can petition the Federal Energy Regulatory Commission to allow utilities to meet up to two-fifths of the standard with electricity savings.

³ H.R. 889 and S. 548. Annual targets are based on average energy deliveries during the two prior calendar years.

⁴ Using a baseline period that lags behind the compliance year – say, by one year – provides utilities, regulators, and stakeholders with concrete energy targets (in kilowatt-hours or therms) for program planning and budgeting. The baseline may be fixed throughout the program, based on energy usage before the standard goes into place. Alternatively, a rolling baseline may be used. For example, the baseline may be average usage during 2007 and 2008 for the 2010 compliance year, average usage during 2008 and 2009 for the 2011 compliance year, etc. Under this approach, the more successful the efficiency programs, the lower the subsequent kWh/therm targets because the updated baseline reflects reduced energy sales.

⁵ H.R. 889 and S. 548 (111th Congress) propose cumulative targets beginning in 2012. Annual figures representing incremental savings implied by the cumulative targets are from Furrey, et al., ACEEE, March 2009 (Table 1). According to ACEEE, programs to stimulate this level of savings would begin in 2011.

⁶ Energy Saving Trust, *Energy Efficiency Commitment Report 2000-2001*, London, 2001.

⁷ Ofgem, *Carbon Emissions Reduction Target (CERT) 2008-2011 Supplier Guidance*, London, 2007.

⁸ David Crossley, "White certificates in Australia: States take the lead," *DSM Spotlight*, No. 32, January 2009, at <http://www.ieadsm.org/Files/Exco%20File%20Library/Spotlight%20Newsletters/IEA%20DSM%20Spotlight%20newsletter-Issue%2032-January%202009.pdf>.

⁹ Energy efficiency certificates are also known as "white certificates" or "white tags." In January 2003 the New South Wales scheme became the first such trading system in the world. See D.J. Crossley, "Tradeable energy efficiency certificates in Australia," *Energy Efficiency*, Vol. 1, No. 4, November 2008, at <http://www.springerlink.com/content/px01053860418332/fulltext.pdf>.

¹⁰ Maggie Eldridge, R. Neal Elliot, and Max Neubauer, ACEEE, *State-Level Energy Efficiency Analysis: Goals, Methods, and Lessons Learned*, proceedings of the 2008 ACEEE Summer Study on Energy Efficiency in Buildings. The study is based on state, regional, and national level analyses with study periods ranging from five to 20 years.

¹¹ For example, in developing its draft 6th Power Plan, the Northwest Power and Conservation Council estimates achievable, cost-effective conservation in the four-state region at 21 percent of the 20-year forecasted (medium-case) electric load. The identified conservation would meet about 85 percent of medium-case load growth in the region while significantly reducing both system cost and risk. Communication with Charlie Grist, Council senior analyst, August 14, 2009. Study results at <http://www.nwccouncil.org/energy/crac/Default.htm>.

¹² American Gas Association, *Natural Gas Utility Energy Efficiency Portfolios Report: 2007 Program Year*, December 2008, at <http://www.aga.org/NR/rdonlyres/122417D7-E42E-49B4-8EE8-9AB26E421B4F/0/1208EEREPORT.pdf>.

¹³ Steven Nadel, ACEEE, Replies to Questions at the April 22, 2009, Hearing on Energy Efficiency Resource Standards, May 12, 2009.

¹⁴ See NAPEE, 2006, at http://www.epa.gov/cleanenergy/documents/napee/napee_report.pdf.

¹⁵ See Nadel.

¹⁶ 2010 in-service date. Jeff King, "Proposed Combined-cycle Power Plant Planning Assumptions: 6th Northwest Conservation and Electric Power Plan," Oct. 15, 2008, at <http://www.nwccouncil.org/energy/grac/meetings/2008/10/Combined-cycle%20planning%20assumptions%20-%206P%20Draft%20101608.ppt#526,14,Natural%20gas%20price%20forecasts>.

¹⁷ The Energy Information Agency estimates the levelized cost of new conventional baseload plants in 2015 at about 6 cents per kWh (2006 dollars). See *Annual Energy Outlook 2008*, p. 69, at [http://www.eia.doe.gov/oiaf/aeo/pdf/0383\(2008\).pdf](http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2008).pdf).

¹⁸ The natural gas price forecast is consistent with a recent forecast by Lazard, "Levelized Cost of Energy Analysis," presented at a meeting of the National Association of Regulatory Utility Commissioners, June 2008, at [http://www.narucmeetings.org/Presentations/2008%20EMP%20Levelized%20Cost%20of%20Energy%20-%20Master%20June%202008%20\(2\).pdf](http://www.narucmeetings.org/Presentations/2008%20EMP%20Levelized%20Cost%20of%20Energy%20-%20Master%20June%202008%20(2).pdf).

¹⁹ When efficiency displaces fossil-fuel generation, it has a negative carbon footprint.

²⁰ Sample calculation for a wires-only company. See Regulatory Assistance Project, *Revenue Decoupling Standards and Criteria: A Report to the Minnesota Public Utilities Commission*, June 2008, p. 36, at http://www.raponline.org/Pubs/MN-RAP_Decoupling_Rpt_6-2008.pdf. A similar calculation for a vertically integrated utility resulted in a seven percent

change in earnings with each one percent change in utility sales.

²¹The exception is a utility with retail rates below wholesale power prices and no adjustment mechanism for fuel and purchased power. In this case, a decrease in sales can increase profits because the additional wholesale power revenue (or avoided wholesale power cost) may exceed the retail revenue loss. During the Western Energy Crisis in 2000-01, for example, utilities without a power cost adjustment had a strong incentive to conserve energy. But at that point it was too little, too late.

²²Costs that vary directly with consumption and production – fuel, variable operation and maintenance, and purchased power costs – typically are excluded from the decoupling mechanism. Fuel and purchased power costs often are addressed through a separate adjustment mechanism.

²³In the “accrual” version of decoupling, these prices are in place for an initial accrual period and subsequently adjusted to reflect over- or under-recovery of allowed revenue. In the “current” version of decoupling, the initial prices are never actually put in place; instead they are used as base prices against which decoupling adjustments are applied in each billing cycle.

²⁴Allowed revenue may be the revenue requirement established in the last rate case or may be a formula designed to permit revenue to change over time to reflect inflation and productivity, to reflect customer growth, or to address another metric. Whatever the formula, decoupling assures that the targeted revenue is actually collected.

²⁵Pamela G. Lesh, “Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling: A Comprehensive Review,” June 30, 2009, at <http://www.raponline.org/Pubs/Lesh-CompReviewDecouplingInfoElecandGas-30June09.pdf>.

²⁶Whether expressed as kWh or therms saved or as reductions in greenhouse gas emissions.

²⁷As previously noted, once an EERS is established, target and funding levels for efficiency are no longer at issue – at least for awhile. Absent such a performance standard, decoupling also would be needed to address the utility throughput incentive in proceedings that set these levels. And without decoupling, utilities will object to any ramp-up in EERS requirements.

²⁸With appropriate customer consent.

²⁹Other reasons for third-party administration may include increasing stakeholder involvement in program design and employing competition among energy efficiency service providers.

³⁰The administering organization may be established by state statute, established by the Commission, or selected through competitive bidding.

³¹In Oregon, the third-party administrator is the Energy Trust of Oregon (ETO, www.energytrust.org). In Wisconsin, the Statewide Energy Efficiency and Renewable Administration is called Focus on Energy (<http://www.focusonenergy.com>). In Vermont, an “Energy Efficiency Utility” (EEU) procures energy efficiency for most utilities in the state. Efficiency Vermont currently serves as the EEU (www.efficiencyvermont.org).

³²See Order No. 09-020 (Docket UE 197), Jan. 22, 2009, p. 27. The Commission clarified and modified the decoupling mechanism in Order No. 09-176, May 19, 2009, at <http://apps.puc.state.or.us/edockets/docket.asp?DocketID=14729>.

³³See order in Docket Nos. 7175 and 7176, pp. 3-4, at <http://www.state.vt.us/psb/orders/2006/files/7175-7176-finalorder.pdf>.

³⁴“Under alternative regulation, CVPS will set rates on the basis of customer load forecasts, taking into account the impacts of load changes arising from factors such as self generation, conservation, efficiency, and load management. These measures help to decouple CVPS’s earnings from its retail sales volumes between rate cases, thereby promoting resource parity.” See order in Docket No. 7336, Sept. 30, 2008, p. 40, at <http://www.state.vt.us/psb/orders/2008/files/7336%20Final.pdf>.

³⁵Final decision in case number 6690-UR-119, Dec. 30, 2008, pp. 15-20, at <http://psc.wi.gov/>.

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Capital Management

The capital cycle that began in 2007 continues for regulated utilities, as aging infrastructure and government policies dictate material upgrades and investment in the system. In this report, we review the scale and scope of spending over the next 5 years. We also analyze patterns from past capital and business cycles in an attempt to provide some tools to identify investment themes.

- We estimate that regulated utilities will spend more than \$300 billion of Cap-ex between 2009 and 2013. This represents approximately 2x depreciation and amortization, and is down only 2% from last year's survey in spite of the current recession.
- This investment should continue to cause an elevated number of rate case filings. We expect 60 rate case filings in the next 18 months. We also estimate over \$100B of external capital needs, including \$20B of equity over the next 5 years.
- In the short term, investors have been attracted to regulated utilities as confidence in the economy has been tested. At this point in the business cycle, the highest quality regulated stocks look fully valued, and we would therefore recommend smaller-cap utilities that carry a little more risk, but represent better relative value. CMS, DPL, and NVE are our favorites.
- In the intermediate term, rate cases and equity issuance schedules should present some of the best catalysts for utility investment. We like AEP over this time period due to its completed equity issuance and resolution of its most significant rate case matter in Ohio.
- In the long term, we like companies that can best manage the execution, rate recovery, and financing risks associated with large investment programs. We like WEC most among this group.

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Investors should consider this report as only a single factor in making their investment decision.

July 16, 2009

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BEGINNING ON PAGE 97**

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Capital Management in the Capital Cycle

We are in the third year of the infrastructure build cycle for regulated utilities that began in 2007. Based on our 2009 capex survey, we now anticipate that the industry will proceed with a pre-dividend free cash flow deficit through at least 2013, but likely significantly longer. We estimate over the next five years, the industry will spend on average 2.0x its annual depreciation and amortization expense growing industry rate base at an average annual pace of 6.3%.

We expect that the risks of this build cycle will offset much of the growth opportunity in share performance through the construction period. This is consistent with the investor experience in the last major infrastructure cycle which extended from 1973–1984. The headwinds we forecast will likely come from the dilutive effect of heightened external capital funding requirements, regulatory risk in a rising rate environment and execution risk associated with a significant construction program. The best performing stocks over the cycle will likely be those spending on infrastructure with the highest public policy support, with the highest quality balance sheets, doing business in the best regulatory jurisdictions.

This report updates: 1) our recommendations and investment strategy, which we believe will maximize shareholder returns over the short, intermediate, and long term; 2) our latest estimates of the drivers and size of the investment ahead; 3) our examination of the business consequences and cost of capital implications for the build cycle from the 1970s and the parallels to today; 4) our analysis of utility regulatory jurisdictions; and 5) our review of the pending rate matters for our coverage universe.

Recommendations and Investment Strategies

We break our views on the group into three time periods: the long term (i.e., the duration of the capital cycle), intermediate term (i.e., one to two years), and short term (i.e., the next six to 12 months.)

In the long term, structural headwinds should persist for regulated utilities, owing to risks associated with capital acquisition, construction execution, and regulatory recovery in a rising rate-base environment. The bulk of this report is focused on these long run trends. As a result of these trends, we would be owners of the most constructive regulatory jurisdictions, the strongest balance sheets, and most capable managements. We acknowledge, however, that many of the names that fit this description are pricey at the moment, following a year of investor defensiveness and caution. One from the group that we believe does screen attractively is Wisconsin Energy (WEC). We like WEC due to solid management, consistent Wisconsin regulation, and the earnings and rate base growth it should derive from its Oak Creek plant that is in the final stages of construction. Additionally, WEC is one of three regulated utilities we expect to be pre-dividend free cash flow positive over the next several years.

In the intermediate term, we are looking for potential catalysts around rate case filings and equity issuance schedules. Given that AEP has essentially concluded its Electric Security Plan in Ohio, set its guidance based on trough dark spread margins for off-system sales, and has cleared its equity issuance needs for the foreseeable future with a \$1.7B offering in April, we like its positioning relative to the regulated group.

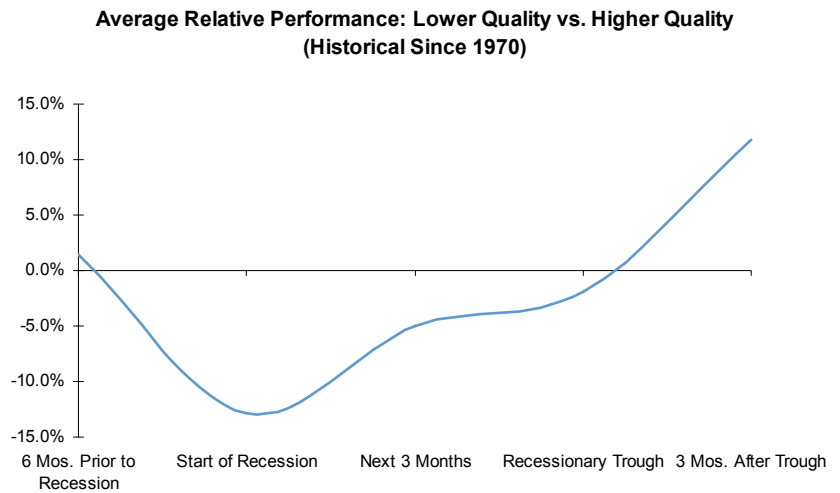
In the short term, we believe the investment winners will be driven by macro fund flows in support of fundamentals. Based on the precedent of previous recessions, higher quality utility names with good liquidity attract investors during the earlier stages, and as the recession matures, investors move out the risk curve to smaller- and mid-cap names that are less liquid. The reasons for this are two-fold: investors add risk as the economy recovers to better participate in the upswing, and the early-stage bid that goes to the highest quality names also creates a relative pricing disparity that allows the smaller less liquid utilities to represent better value. We recommend CMS, DPL, and NVE among this smaller-cap group.

The Short Term: Recessions Drive a Quality Trade

As we have seen, when the economy enters a recession, investor funds tend to migrate toward regulated utilities. Further, in the early throes of recession, the funds flow into higher quality regulated utilities versus lower tier regulated utilities. Higher quality names would be characterized by defensive qualities identified as superior credit access (higher credit ratings), secure and growing dividends, located in supportive regulatory districts, and exhibiting superior trading liquidity for ease of entry and exit. The utilities we classify as higher quality would be DUK, ED, NST, PCG, PGN, SO, WEC, and XEL. As a group, these high quality stocks outperformed the lower tier universe by 21% from 6 months prior to the recession's beginning to the March trough.

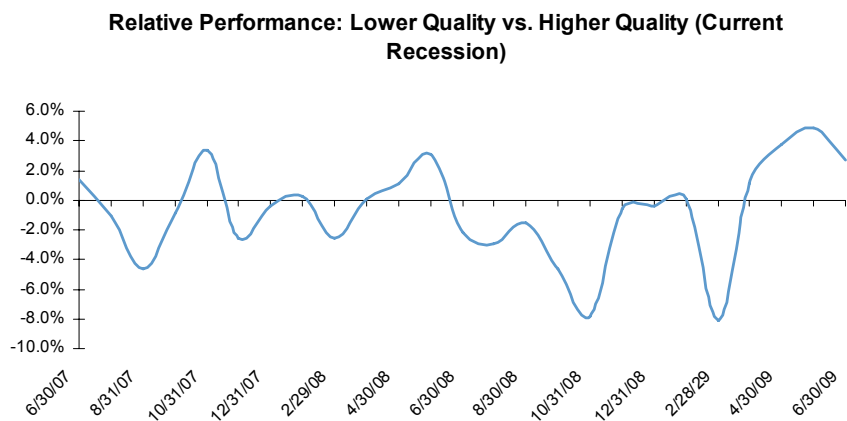
On a broader look at past recessions, this pattern also holds. The higher quality / lower tier pairing has produced on average 18% returns beginning 6 months prior to the recession through the recession's trough. This performance is the average of the recessions since 1970. Conversely, as the market perceives an economic recovery, lower tier names begin to outperform higher quality names. In the recessions since 1970, lower tier utilities outperformed higher quality by 22% from trough to 6 months post-recession, while outperformance of the lower tier in the current recession is about 12% through June 2009 from March.

Figure 1: High Quality Outperforms Heading Into Recessions; Trails Heading Out



Source: FactSet, Barclays Capital estimates.

Figure 2: Lower Quality Names Recently Starting to Outperform



Source: FactSet, Barclays Capital estimates.

At this point, and in spite of lower tier performance since March, a significant valuation gap persists, favoring smaller, less liquid names.

Figure 3: Relative Valuations Higher Quality vs. Lower Quality

Group	2010 P/E	Current P/BV	Dividend Yield	Payout Ratio
Higher Quality	11.6x	1.5x	5.3%	65.3%
Lower Quality	10.7x	1.2x	5.6%	64.0%

Source: FactSet, Barclays Capital estimates.

The Intermediate Term: Rate Case Timing and Equity Needs Provide Catalysts

Continued FCF Deficits Will Require Equity / Rate Cases

Based on the capex survey we have performed associated with this report, we continue to see net free cash flow deficits for the group well into next decade (see Figure 4). In fact, the biggest surprise in this year's survey was the fact that spending only came down 2% versus our 2008 work for overlapping years. As a result, the significant capital raising appetite shown by the group in 2009 year-to-date appears to be just the tip of the iceberg. In order to maintain current debt/cap ratios, we anticipate that the regulated utility group will need to raise at least \$100 billion in debt and equity to complement retained earnings over the next five years.

Figure 4: Capex Forecast Changes, y/y

(\$ in millions)

	2008E	2009E	2010E	2011E	2012E	Total
2006 Estimates	\$39,129	\$37,588	\$37,053	n/a	n/a	n/a
2007 Estimates	\$52,714	\$51,745	\$51,881	n/a	n/a	n/a
2008 Estimates	\$61,338	\$60,472	\$61,102	\$63,350	\$62,301	\$308,562
2009 Estimates	\$63,335	\$58,144	\$59,819	\$62,057	\$63,282	\$306,637
% Increase ('09 v. '06)	61.9%	54.7%	61.4%	n/a	n/a	n/a
% Increase ('09 v. '08)	3.3%	-3.8%	-2.1%	-2.0%	1.6%	-0.6%

Source: Barclays Capital estimates, company filings.

Figure 5: Forecasted Cash Flow and Capital Needs

Capital and Cash Flow Projections Shareholder Owned Regulated Utilities (\$ in millions)						
	2008P	2009E	2010E	2011E	2012E	2013E
Debt	\$320,507	\$337,471	\$356,002	\$374,239	\$389,850	\$402,079
Equity	\$252,380	\$267,282	\$281,748	\$296,722	\$311,595	\$326,117
Total Capital	\$572,887	\$604,753	\$637,750	\$670,961	\$701,446	\$728,195
Equity %	44%	44%	44%	44%	44%	45%
Cash from Operations	\$45,550	\$46,730	\$48,197	\$51,148	\$56,013	\$59,853
CapEx	(\$63,335)	(\$58,144)	(\$59,819)	(\$62,057)	(\$63,282)	(\$62,527)
Dividends	(\$10,879)	(\$11,205)	(\$11,541)	(\$11,888)	(\$12,244)	(\$12,611)
Free Cash, Post Div.	(\$28,664)	(\$22,619)	(\$23,164)	(\$22,797)	(\$19,514)	(\$15,285)
Debt Issued (Retired)	\$22,931	\$16,964	\$18,531	\$18,237	\$15,611	\$12,228
Equity Issued (Retired)	\$5,733	\$5,655	\$4,633	\$4,559	\$3,903	\$3,057
Assumptions / Drivers						
Retained Earnings Growth	9.5%	7.1%	6.3%	5.9%	5.3%	4.5%
Cash from Operations Change		2.6%	3.1%	6.1%	9.5%	6.9%
CapEx Change	14.4%	-8.2%	2.9%	3.7%	2.0%	-1.2%
Dividend Growth	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Proportion Returned to (Drawn from) Debt	80%	75%	80%	80%	80%	80%
Proportion Returned to (Drawn from) Equity	20%	25%	20%	20%	20%	20%

Note: Figures reflect Barclays Capital utility coverage scaled up by a factor of 1.08x to reflect companies not in Barclays coverage universe.

Source: Company filings, Barclays Capital estimates.

The following table takes a company by company look at our estimate of equity needs.

Figure 6: Projected Equity Issuance Schedule

Company	Ticker	Amount & Year of Issuance (\$ in millions)				
		2008	2009E	2010E	2011E	2012E
Alliant Energy	LNT	1		0	350 (1)	
Ameren Corp.	AEE	154	100	100	100	500 (1)
American Electric Power	AEP	159	1,691 (1)	150	150	150
CMS Energy Corp	CMS	9	173 (1)			
Consolidated Edison	ED	51	400 (1)	550 (1)	550 (1)	400 (1)
Dominion Resources Inc	D	240	500	400	250	250
Duke Energy Corp	DUK		360	150	300	300
FPL Group Inc	FPL	41	403 (1)	200	500 (1)	500 (1)
Great Plains Energy	GXP	15	432 (1)			
Hawaiian Electric Indust.	HE	136	0	45	45	45
NiSource Inc	NI	1	60			
Northeast Utilities	NU	6	370 (1)		350 (1)	
NV Energy	NVE	6		150 (1)		
PG&E Corp	PCG	225	225	400	150	150
Pinnacle West Capital	PNW		25	300 (1)	25	25
Pepco Holdings	POM	316	29	300 (1)	350 (1)	100
Portland General	POR		175 (1)			
Progress Energy	PGN	132	469 (1)	300	300	300
Public Service Entrp Group	PEG	0				
Sempra Energy	SRE	18	23	23	23	23
Southern Co	SO	474	500	600	600	600
TECO Energy Inc	TE	22	25	25	25	25
Westar Energy	WR	294			60	
Xcel Energy	XEL	353	75	75	75	75
Total		\$3,265	\$6,494	\$3,768	\$4,203	\$3,443

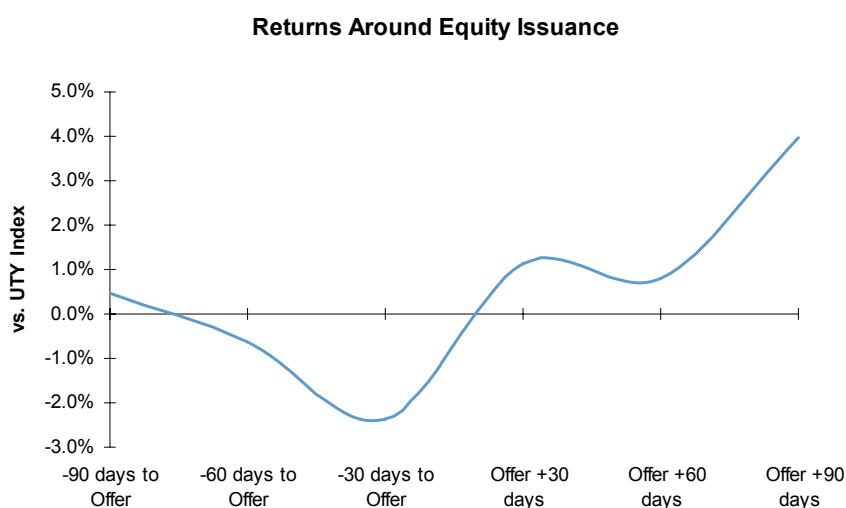
(1) Represents actual or estimated marketed offerings, as opposed to DRIP or dribble programs.

Note: Gray cells indicate actual amounts issued

Source: Company filings, Barclays Capital estimates.

As an investment tool, these issuance events provide meaningful catalysts to performance. When the market anticipates an equity need, the stock will tend to underperform the group. In contrast, once the equity issuance has occurred and the new shares have been digested by investors, the median stock will outperform the group. Financing needs having been met, and balance sheets shored up provide more than ample reason to justify this behavior. Figure 7 shows the value of this catalyst in light of the issuance-heightened environment for the last 12 months.

Figure 7: Stocks Perform Well Once Equity Has Been Cleared

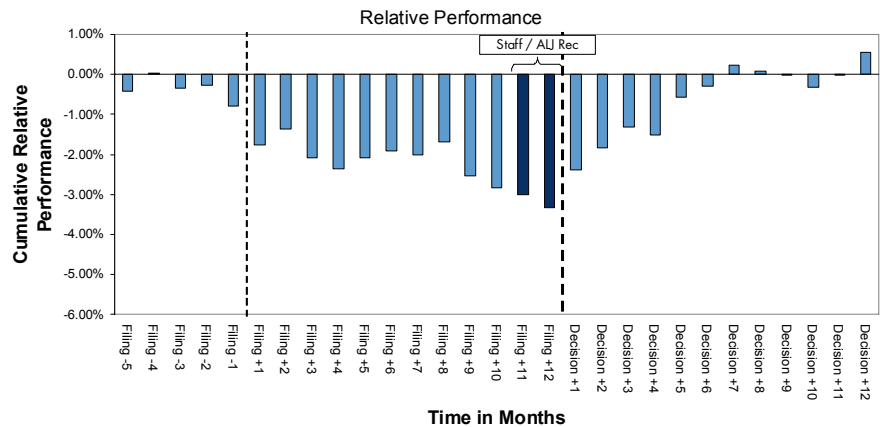


Source: FactSet.

Rate Cases Provide Trading Opportunities

Also during a capital cycle, tactical opportunities will develop around rate case timing, since rate case filings tend to cause uncertainty around future earnings. As a result a risk premium is attached to utility stocks whose subsidiaries are anticipated to file a rate case or are in the rate case process. As the rate case process moves forward, more and more clarity begins to develop around the parameters of a potential order. Once the staff recommendation is released the likely worst case scenario can be understood and once the ALJ recommendation is made, the final parameters of an order can be closely estimated. From this point forward the higher risk premium created as a result of rate case uncertainty abates. This tradable phenomenon is shown in Figure 8.

Figure 8: Relative Performance and Rate Case Timing

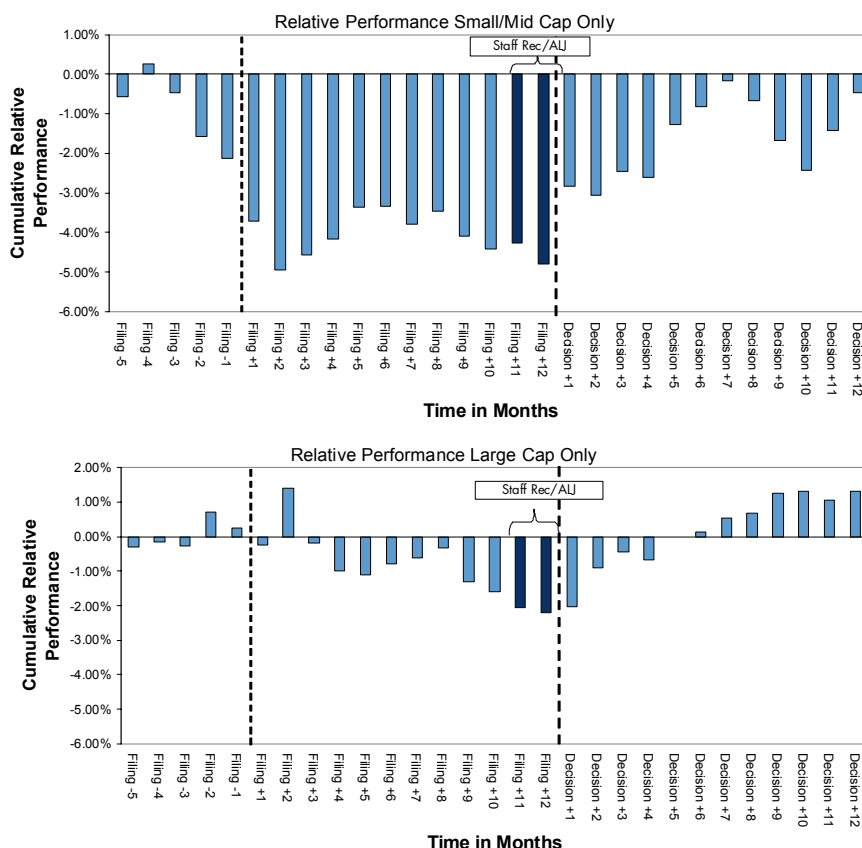


Source: SNL Financial, Bloomberg, Barclays Capital estimates.

All else equal, if an investor shorts a stock four months prior to a rate case filing through the time of the ruling he/she should outperform the regulated group by 334 basis points (bp), on average. If in turn that same investor then buys the utility 12 months after the rate case filing through 12 months after the decision he/she should earn, on average, an additional 388 bp relative to the regulated group. It is important to note that this analysis last year showed relative returns of 398 bp and 644 bp, respectively. The returns from the trade were dampened as a result of 2008 being a very volatile year in which broader systemic risks drove the market more than any company specific risk such as rate cases. As the market moves toward a more "normal" environment across the intermediate term, and away from trading around broader systemic risks and fund flow dynamics in the short run, we would expect this trade's effectiveness to improve.

Given that most small-cap regulated utilities are only single or dual jurisdictional and most large-cap regulated utilities are multi-jurisdictional the risk premium during a rate case should be larger for smaller-cap utilities.

Figure 9: Rate Cases and Relative Performance by Cap Size



Source: SNL Financial, Bloomberg, Barclays Capital estimates.

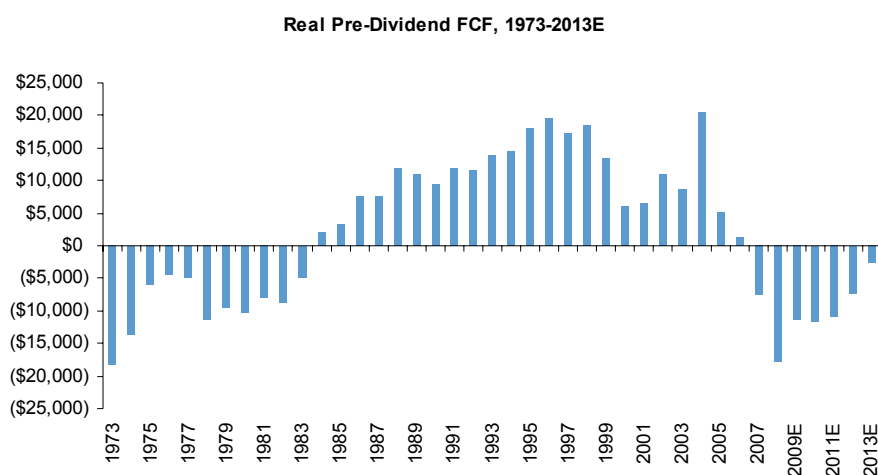
This is in fact the case, as shown in Figure 9. The trading returns from the same general “short-then-long” strategy as described above is 480 bp and 433 bp for small cap utilities and 221 bp and 353 bp for large cap utilities. Before the systemic-risk-driven market of 2008, for the same strategies, our study showed excess returns of 916/828 bp and 266/532 bp for small- and large-cap utilities, respectively.

The Long Term: Secular Headwinds Still In Place

In our estimation, the regulated utility group entered a capital cycle beginning in 2007 characterized by pre-dividend FCF deficits. These negative cash flows exacerbate risks related to execution, financing, and regulation, leading to our more negative view of the group in the longer term.

As we’ve noted, aggregate pre-dividend free cash flow for the regulated utilities space turned negative in 2007. Figure 10 highlights the changes in FCF dating back to 1973, in 2008 dollars and includes our estimate of the deficits we anticipate through 2013.

Figure 10: Pre-Dividend FCF throughout Capital Cycles, in 2008 \$

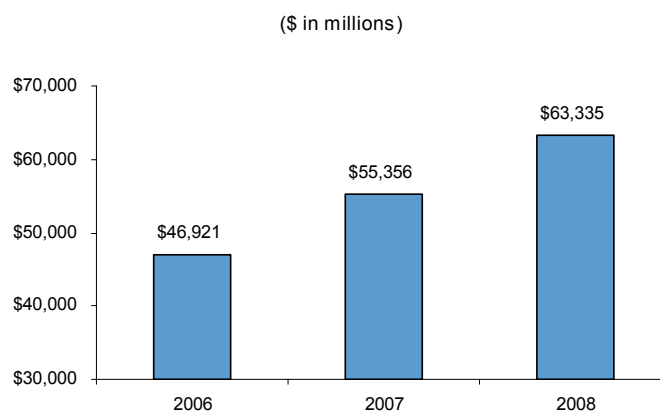


Source: FactSet, Barclays Capital estimates.

The current cycle is marked by four drivers: 1) an aging post-war infrastructure, 2) environmental policy forcing upgrades to old plant and equipment, 3) the implementation of new technologies (e.g., solar, wind, and smart grid), and 4) the addition of new transmission to account for renewable energy hook-ups and improved system redundancy. Due to the very extensive public policy drivers to this build, we estimate it could ultimately last as long as or even exceed the '73 to '84 experience.

As shown in Figure 11, we estimate that capex rose 14% for regulated utilities in 2008. That marked the second year of exceptional growth in spending.

Figure 11: Three Year Historical CapEx



Source: Company filings, Barclays Capital estimates.

We expect this trend to flatten in 2009, as recessionary pressures coupled with prohibitively expensive – or inaccessible – external capital, has led some utilities to cancel or defer spending on growth-oriented projects. At the Edison Electric Institute conference in Arizona last November, several companies announced a first round of cuts that averaged between 10%–15% versus previous levels. In the final tally, however, spending projections for 2009 are estimated to be about 8% lower than our 2008 figures. More surprisingly, the comparison of capital spending plans for overlapping years of our 2009 vs 2008 survey were only down 2%. We can only conclude that relatively little of the group's spending is discretionary (see Figure 12).

Figure 12: CapEx Forecast by Type of Spending

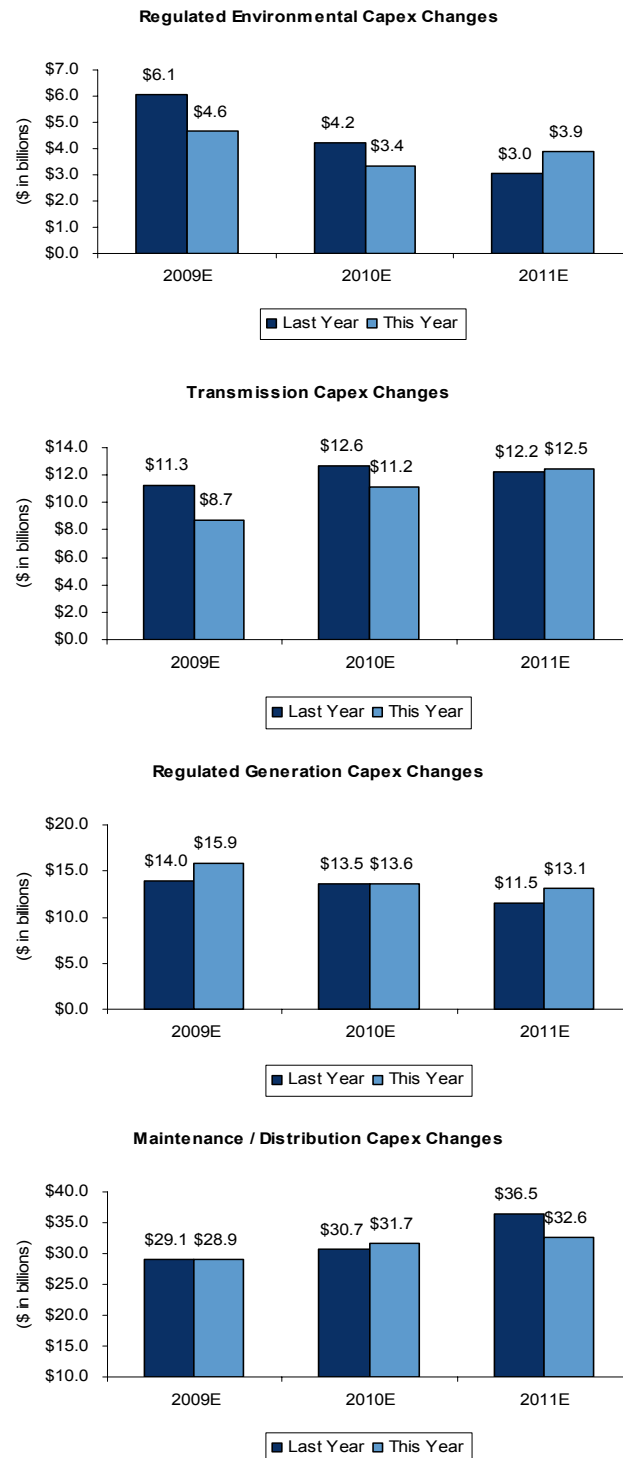
Capital Expenditure Projections									
Shareholder Owned Regulated Utilities									
(\$ in millions)									
	2006	2007	2008	2009E	2010E	2011E	2012E	2013E	Total
Maintenance / Distribution				\$28,950	\$31,654	\$32,601	\$35,390	\$36,760	\$165,354
Generation				15,855	13,620	13,062	12,518	12,190	\$67,246
Environmental				4,644	3,359	3,886	2,218	2,278	\$16,384
Transmission				8,695	11,187	12,508	13,157	11,299	\$56,845
Total	\$46,921	\$55,356	\$63,335	\$58,144	\$59,819	\$62,057	\$63,282	\$62,527	\$305,829
YY Increase		18.0%	14.4%	-8.2%	2.9%	3.7%	2.0%	-1.2%	

Note: Figures reflect Barclays Capital utility coverage scaled up by a factor of 1.08x to reflect companies not in Barclays coverage universe.

Source: Company filings, Barclays Capital estimates.

A breakdown in the categories of spending is contained in Figure 13. On a year over year survey comparison, the largest declines appear in regulated environmental spending, and in transmission. The regulated environmental spending reduction is a result of improvements in the effectiveness of coal pollution control programs as the spending nears its conclusion. The decline in transmission is largely the result of permitting delays, with the spending likely deferred, not eliminated. Strength in generation and distribution are largely related to renewable resources and automatic metering infrastructure.

Figure 13: Year-over-Year CapEx Forecast Changes



Source: Company filings, Barclays Capital estimates.

Despite the near-term drop in capex, the rate of spending still exceeds even the inflated spending that began in 2007. As a result of this level of spending, we are still seeing meaningful growth in rate base across the sector.

Figure 14: Rate Base Growth Projections

Shareholder Owned Regulated Utilities
(\$ in millions)

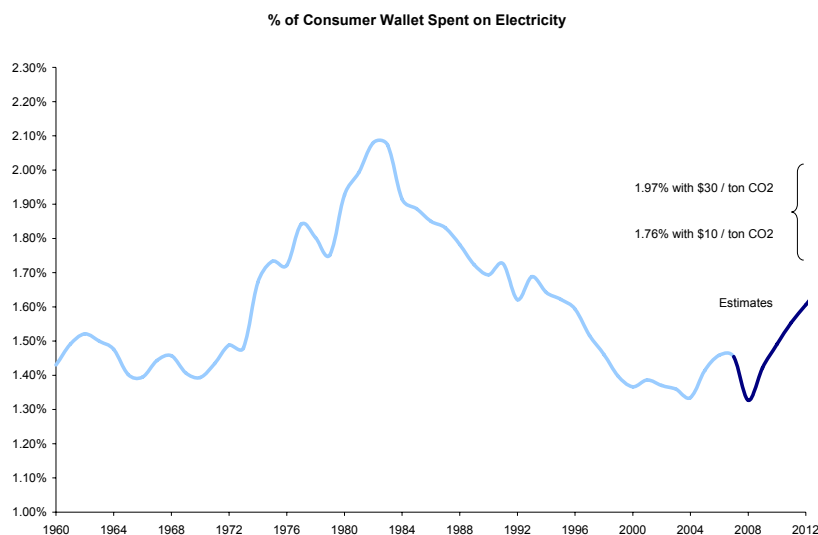
	2008	2009E	2010E	2011E	2012E	2013E
Rate Base	\$452,887	\$492,335	\$524,266	\$555,480	\$586,449	\$616,113
Capital Expenditures	\$63,335	\$58,144	\$59,819	\$62,057	\$63,282	\$62,527
D&A	\$23,887	\$26,213	\$28,605	\$31,088	\$33,619	\$36,120
Rate Base Additions	\$39,448	\$31,931	\$31,214	\$30,970	\$29,663	\$26,407
Rate Base Growth %	9.5%	7.1%	6.3%	5.9%	5.3%	4.5%

Source: Company filings, Edison Electric Institute, Barclays Capital estimates.

What Happens to Consumer Costs?

An interesting side effect of the current recession is the relief it poses to what we've previously seen as an inexorable rise in prices to consumers. The good news is that the decline in fuel rates has created a soft spot where overall prices are unlikely to rise in 2009 or 2010 in spite of rate base growth. The bad news is that higher forward fuel prices, continued additions to rate base, and the potential for significant new costs from government environmental mandates (CO2) will likely force significant inflation next decade. Figures 15 and 16 track our forecasts for prices, Figure 15 as compared to consumer spending over the long run and Figure 16 showing the driving forces over the next 5 years.

Figure 15: Historical and Projected Price to Consumers



Source: EIA, Bureau of Economic Analysis, Barclays Capital estimates.

Figure 16: Projected Revenue Requirements

Actual and Projected Industry Revenues & Costs
(\$ in millions)

	2006	2007	2008	2009E	2010E	2011E	2012E	2013E
Industry Revenues	\$326,506	\$343,703	\$365,355	\$365,355	\$365,741	\$351,431	\$382,382	\$408,022
Plus: Incremental Fuel				(\$14,372)	(\$25,882)	\$18,103	\$13,267	\$11,308
Plus: Incremental Environmental				\$1,164	\$641	\$794	\$428	\$399
Plus: Incremental Transmission				\$2,180	\$2,136	\$2,556	\$2,537	\$1,979
Plus: Incremental Generation				\$3,975	\$2,601	\$2,669	\$2,414	\$2,135
Plus: Maintenance & Distribution				\$7,439	\$6,195	\$6,828	\$6,995	\$6,600
Incremental Revenue Addition				\$386	(\$14,309)	\$30,951	\$25,640	\$22,420
New Projected Revenue Base	\$326,506	\$343,703	\$365,355	\$365,741	\$351,431	\$382,382	\$408,022	\$430,443
% Revenue Increase	9.6%	5.3%	6.3%	0.1%	-3.9%	8.8%	6.7%	5.5%
Total GWh Base	3,660,969	3,669,919	3,764,561	3,721,562	3,609,915	3,653,234	3,707,634	3,762,845
Barclays Demand Forecast	0.2%	2.6%	-1.1%	-3.0%	1.2%	1.5%	1.5%	1.5%
Total GWh Used	3,669,919	3,764,561	3,721,562	3,609,915	3,653,234	3,707,634	3,762,845	3,818,877
Nominal \$ / MWh Price	\$88.97	\$91.30	\$98.17	\$101.32	\$96.20	\$103.13	\$108.43	\$112.71
% Nominal Increase	13.8%	2.6%	7.5%	3.2%	-5.1%	7.2%	5.1%	3.9%

Source: EIA, Edison Electric Institute, Barclays Capital estimates.

Regulatory Implications of a Capital Cycle

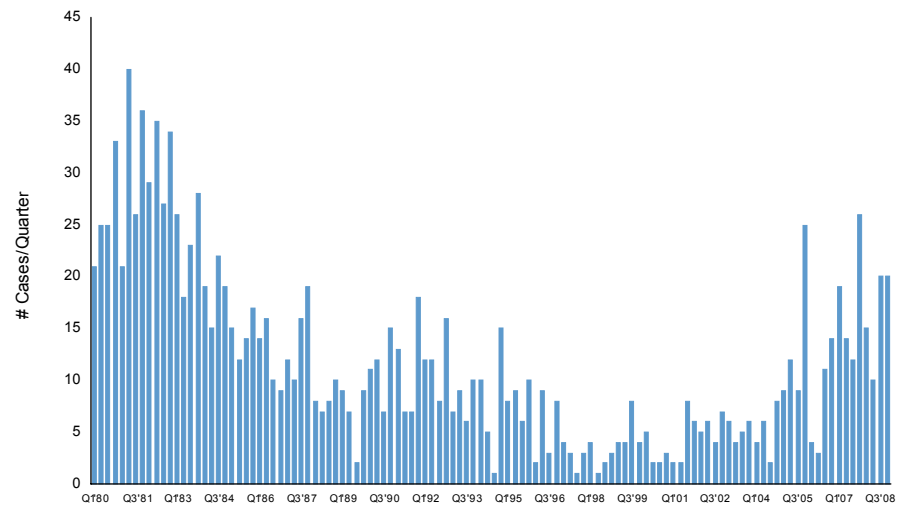
The current capital cycle is resulting in these negative long-term regulatory trends mimicking the 70's capital cycle:

- 1) An increase in the frequency of rate cases as companies attempt to recover the capital they are spending on a timelier basis;
- 2) A squeezing of spreads as in the face of large and frequent rate increase requests, regulators tend to scrutinize allowed ROEs for excess returns; and
- 3) An expansion in Regulatory lag, the gap between authorized returns and earned returns.

Frequency of Rate Cases on the Rise

Due to the cap-ex outlined above, we expect the industry to continue a busy schedule of rate cases in the near term. In fact, rate cases may increase if managements recognize the window of opportunity to raise base rates while potentially lowering customer's bills as a result of a reduction in fuel and purchased power pass through costs. We forecast 60 rate cases over the next 18 months, which includes 24 to be decided by year-end 2009 and 36 to be decided thereafter.

Figure 17: Historical Quarterly Number of Rate Cases



Source: SNL Financial, Federal Reserve, Barclays Capital estimates.

A historical summary of the last 17 years of rate case outcomes is shown in Figure 18.

Figure 18: Rate Case Statistics

Date	Electric: Allowed Return on Equity (%)	# of Electric Rate Cases	Gas: Allowed Return on Equity (%)	# of Gas Rate Cases
2009 1Q	10.53	10	10.24	4
2008	10.33	33	10.39	32
2007	10.31	37	10.23	34
2006	10.45	26	10.40	13
2005	10.54	29	10.36	21
2004	10.88	19	10.63	22
2003	10.98	18	10.95	23
2002	11.22	11	11.09	17
2001	11.12	10	10.96	5
2000	11.58	9	11.35	11
1999	10.65	5	10.74	6
1998	11.91	9	11.51	10
1997	11.33	10	11.31	10
1996	11.40	18	11.12	17
1995	11.59	26	11.44	13
1994	11.21	27	11.24	24
1993	11.48	26	11.37	37
1992	12.06	38	11.99	26

Source: SNL Financial

Return Spreads Tightening

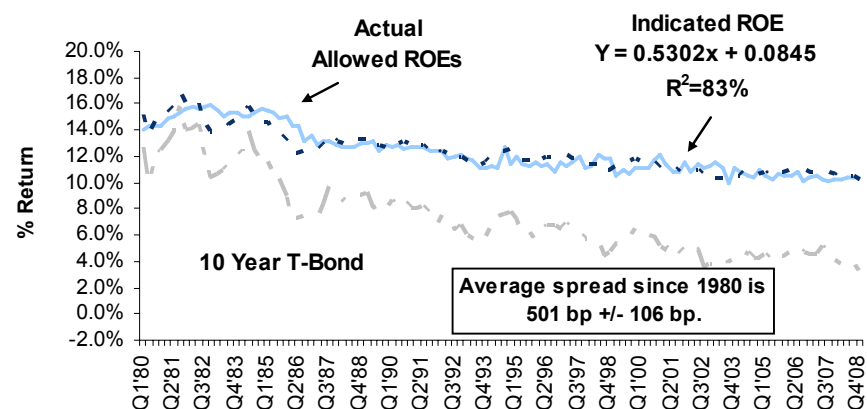
Figure 19: Average Rate Case Outcomes & Relationships, 2005-2009

Year	Allowed ROE	Yield on 10-Year Treasury	Spread (bps)	Yield on Moodys Baa	Spread (bps)
2005	10.54%	4.32%	622	6.08%	446
2006	10.45%	4.77%	567	6.47%	398
2007	10.23%	4.65%	557	6.52%	371
2008	10.35%	3.60%	675	7.40%	295
1Q09	10.22%	2.72%	750	8.23%	199

Source: RRA, SNL Financial.

As shown in Figure 19 the spreads of allowed ROEs to treasury yields tightened from 2005 to 2007 before widening again in 2008 and 2009. We believe this has more to do with the decline in treasury yields as a result of monetary policy versus any increase in allowed ROEs awarded by commissions. In fact, allowed ROEs, while rising slightly in 2008 have fallen back in 1Q09 to near 2007 levels. Moreover, when compared versus corporate bond rates, spreads to allowed ROEs have continued to tighten since 2005 and as the capital cycle began in 2007. Spreads of allowed ROEs to corporate yields have tightened from 446 bp in 2005 to 199 bp in 1Q09, a narrowing of 247 bp (55%). Overall, allowed ROEs are more correlated with corporate bond yields over time than with treasury yields.

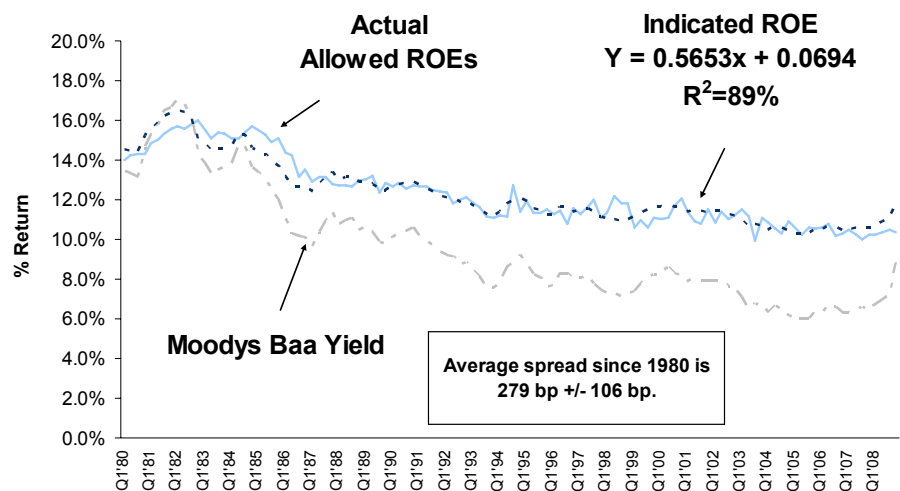
Figure 20: Allowed ROEs vs. 10 Year Bond Yields



Source: SNL Financial, Federal Reserve, Barclays Capital estimates.

In 1,359 cases since 1980 the average outcome has been 501 bp greater than the 10 year treasury yield with a standard deviation of 106 bp. Our regression analysis shows that applying a 0.5302 multiplier to the 10 year yield and adding 845 bp results in an R^2 of 83%. This would have implied a 10.39% allowed ROE in 2008 versus the actual allowed ROE of 10.35%.

Figure 21: Allowed ROEs vs. Corporate Bond Yields



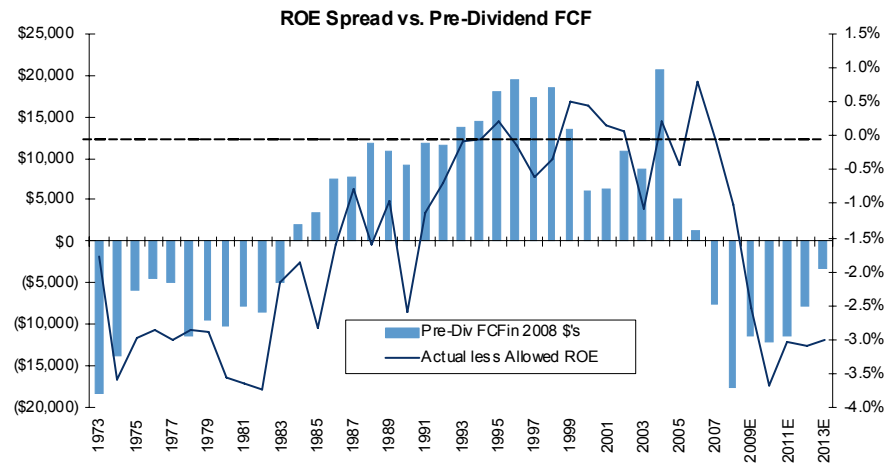
Source: SNL Financial, Federal Reserve, Barclays Capital estimates.

In the same period since 1980 the average outcome for allowed ROEs has been 279 bp higher than the Moody's Baa Corporate Yield with a standard deviation of 106 bp. Our regression analysis shows that applying a factor of 0.5653 to the corporate bond yield and adding 694 bp results in an R^2 of 89%. This would have implied an allowed ROE of 11.94% in 2008 versus the actual ROE of 10.35%.

Regulatory Lag on the Rise

During periods of rising capital expenditures and rate base as well as rising costs, utilities with historic test years cannot fully recover those rising costs over time. That is, during periods of free cash flow deficits, revenues meant to offset depreciation, capital, and operating costs, for utilities with historic test years are often delayed versus the actual incurrence of these costs due to the review process. Figure 22 shows the historical relationship between regulatory lag and pre-dividend free cash flow. We have adjusted pre-dividend free cash flow to be presented consistently in 2008 dollars using the GDP deflator.

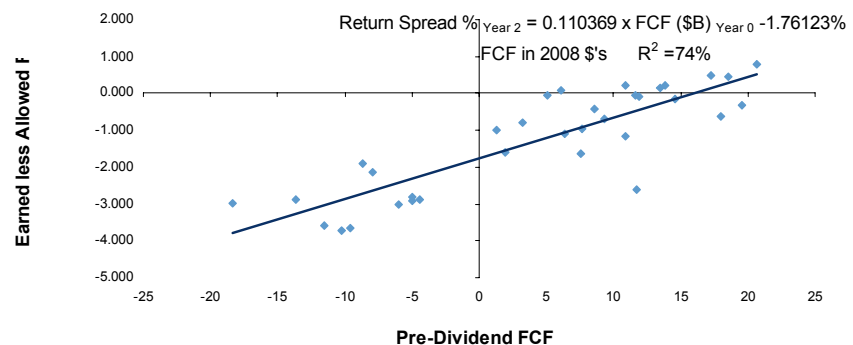
Figure 22: Regulatory Lag Throughout Capital Cycles, Historical & Projected



Source: FactSet, Edison Electric Institute, SNL Financial, Federal Reserve, Barclays Capital estimates.

The relationship, with a two year lag between the pre-dividend FCF and the ROE gap, has been well correlated with an R^2 of 74%. Our regression analysis is shown in Figure 23.

Figure 23: Pre-Dividend FCF vs. ROE Spread



Source: FactSet, Edison Electric Institute, SNL Financial, Federal Reserve, Barclays Capital estimates.

This relationship indicates that utilities earn 176 bp below their allowed returns two years hence from a breakeven FCF. Each \$1 billion in FCF variance alters this regulatory lag by approximately 11 bp. We project negative but improving FCF deficits versus 2008 in 2009 through 2011, and another improvement in 2012 and 2013. This would lead to projected earned ROEs between 7.5% and 8.0% through 2013. Correcting for the average discrepancy between our projections and actual ROEs since 2005 of 73 bp would lead to projected earned ROEs of between 8.2% and 8.75%.

Figure 24: Historical and Projected ROEs

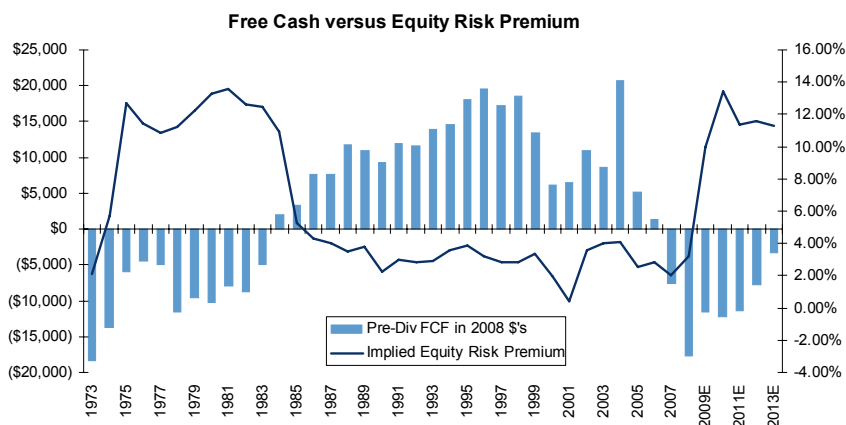
	2005A	2006A	2007A	2008A	2009E	2010E	2011E	2012E	2013E
Pre-Dividend FCF	\$4,731	\$1,250	(\$7,128)	(\$17,605)	(\$11,563)	(\$12,206)	(\$11,394)	(\$7,713)	(\$3,361)
Projected Allowed ROE	10.50%	10.38%	10.23%	10.35%	10.56%	11.16%	10.97%	10.79%	10.60%
Projected Over- (Under) Earn	-0.85%	0.07%	-1.24%	-1.62%	-2.55%	-3.70%	-3.04%	-3.11%	-3.02%
Projected Earned ROE	9.65%	10.45%	8.99%	8.73%	8.01%	7.46%	7.94%	7.68%	7.58%
Actual ROE	10.06%	11.16%	10.17%	9.34%	8.74%	8.19%	8.67%	8.41%	8.31%
Discrepancy	-0.41%	-0.71%	-1.18%	-0.62%	-0.73%	-0.73%	-0.73%	-0.73%	-0.73%

Source: FactSet, Edison Electric Institute, SNL Financial, Federal Reserve, Barclays Capital estimates.

The Capital Cycle Could Cause Risk Premiums to Rise

As FCF deficits have increased, this has in turn increased balance sheet strain, regulatory scrutiny, and execution risk. Investors may, as a result, demand a higher risk premium. We calculated the historical implied equity risk premium for the utilities sector as follows: Equity risk premium = earnings yield – 10-year bond yield (risk free rate). Figure 25 shows the historical FCF deficits or premiums adjusted into 2008 dollars using the GDP deflator and the equity risk premium.

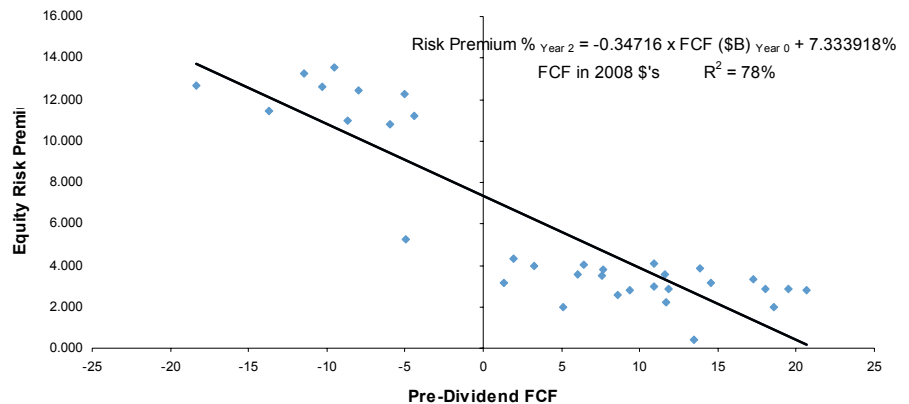
Figure 25: Risk Premiums Throughout Capital Cycles, Historical & Projected



Source: FactSet, Edison Electric Institute, SNL Financial, Federal Reserve, Barclays Capital estimates.

Regressing the equity risk premium versus pre-dividend FCF deficits, with a two year lag displayed a strong relationship with an R^2 of 78%, as shown in Figure 26.

Figure 26: Pre-Dividend FCF vs. Risk Premiums



Source: FactSet, Edison Electric Institute, SNL Financial, Federal Reserve, Barclays Capital estimates.

Based upon this regression relationship we would expect to see risk premiums spike to the area of 13.5% by 2010 versus the 3.17% seen in 2008, before moderating in the 11%–12% area from 2011 to 2013. Returns should move lower with the increase in equity risk premiums.

Know Thy Regulator

The increasing importance of regulatory lag and allowed returns throughout the capital investment cycle increases the value of a utility's governing regulatory district(s). Continuing the trend that we have seen historically, the more favorable regulatory districts (corresponding to lower costs of capital) are clustered in the Southeast and upper Midwest, while the more difficult jurisdictions (and higher costs of capital) are typically located in the desert Southwest and Northeast. We point to six key metrics that we believe best bound the risks inherent in particular jurisdictions, and correspond closely to the differences we see in the relative cost of capital from region to region. A more detailed differentiation of these metrics can be found below.

- Elected versus Appointed: Elected commissions have a greater incentive to be focused on end user prices above cost of capital. Appointed commissions have a buffer to the electorate and can act in a more judicial manner.
- Rules Mechanism: Having certain rules in place allows for more consistent, timely, and transparent regulation over time. Features we assess in this category are: Test Year Period, Fuel Clauses, Non-Fuel Spending Trackers, Statutory Decision Limits, Formal IRP Processes, CWIP vs AFUDC, and Decoupling mechanisms.
- Allowed ROEs: A ranking based on the last five rate case outcomes relative to 10-year Treasury levels. Included decisions go back as far as 15–20 years.

- **Settle versus Litigate:** Settlement often works out in a better outcome for all parties and consequently earns the state a better rating.
- **Rate Levels:** The higher the rate, on a relative basis, the greater the difficulty to raise it. Lower absolute rates get a better ranking, as they are less prone to attract customer pushback.
- **Subjective Investor Friendliness Rating:** Based upon three main factors: a track record for reaching decisions that are well defended and within the bounds of testimony; staff reputation, professionalism, and influence; and ability to recognize and address emerging trends.

These six criteria are equal-weighted and receive a value of 1 to 2, with the smaller number representing a better ranking. In the Appendix we have provided our rating details, state commissioner and staff contact information.

While the broad geographical trends of constructive regulation and perceived investor friendliness continue to hold, we have seen some important positive developments in specific states that we think are worth noting. In each state there is a specific regulatory convention (or several) that can be pointed to as driving the significant change in the last year – such as Ohio (incorporation of fuel clause into regulatory scheme), California (bond index-based ROE tracker mechanism), Florida (constructive rate case outcomes in last six months, despite difficult economic conditions), New Mexico (passed a forward test year rule), and Michigan (forward test year, file and implement rules and pre-determination for large investments).

A Recap of State Rankings

We rank the FERC as “above tier 1” given its regulatory return allowance history, appointed nature, investor friendliness, and policy directive. In our 2009 ranking, the top six jurisdictions are Kentucky, Wyoming, Iowa, Idaho, North Carolina, and Florida. The bottom tier consists of New Mexico, Montana, Arizona, Connecticut, Rhode Island, New York, and Maryland. The jurisdictions that dropped one tier from 2008 were Colorado (from tier 1 to tier 2); Arkansas, Indiana, South Carolina, and Wisconsin (from tier 2 to tier 3); Mississippi, Pennsylvania, and Vermont (from tier 3 to tier 4); and Connecticut, Maryland, and Rhode Island (from tier 4 to tier 5). Missouri dropped two tiers from last year (from tier 2 to tier 4). Jurisdictions that moved up two tiers from last year were Florida (from tier 3 to tier 1) and Michigan (from tier 4 to tier 2). The jurisdictions that moved up one tier were North Carolina (from tier 2 to tier 1); California, Minnesota, Ohio, and Texas (from tier 3 to tier 2); Illinois and West Virginia (from tier 4 to tier 3); and New Hampshire (from tier 5 to tier 4).

Figure 27: Tiered State Regulatory Rankings

Tier 1 Lowest Cost Of Capital	Tier 2	Tier 3	Tier 4	Tier 5 Highest Cost of Capital
FERC		Arkansas Delaware District of Columbia Hawaii Illinois		
	Alabama California Colorado Georgia	Indiana Kansas Massachusetts Oregon	Louisiana Maine Mississippi Missouri	Arizona
Florida Idaho Iowa	Michigan Minnesota North Dakota	South Carolina Utah Virginia	Nevada New Hampshire New Jersey	Connecticut Maryland Montana
Kentucky North Carolina Wyoming	Ohio Oklahoma Texas	Washington West Virginia Wisconsin	Pennsylvania South Dakota Vermont	New Mexico New York Rhode Island

Source: SNL Financial, Barclays Capital estimates.

Figure 28: Relative Price-to-Book Valuation of Electric Utilities by Region
(1986-Current, weekly)

Region	Price/Book Ratio	Relative P/B Value
Southeast	1.67x	12.0%
Mid-Atlantic	1.68x	11.6%
Midwest	1.67x	11.4%
Plains	1.52x	3.1%
West	1.50x	1.3%
New England	1.33x	-10.6%
Southwest	1.07x	-28.8%

Source: FactSet, Barclays Capital.

We have anecdotally believed, and been told by Southern Company for some time, that customer and shareholder interests are aligned through regulation. This is the result of a feedback loop by which utilities that keep prices relatively low, and service and reliability relatively high, receive constructive regulatory outcomes. In turn, that company enjoys a lower cost of capital, and can afford the investment necessary to keep prices low and reliability high. In an attempt to assess this theory, we review the intersection between our regulatory rankings, cost of capital tendencies by region – as measured by relative price to book, and customer satisfaction according to JD Power & Associates. Figures 28 & 29 fully support our view that positive and constructive regulation reinforces good utility performance and perception.

Figure 29: Customer Satisfaction, by Quintile

State Ranking Quintiles	Avg. JD Power Ranking (out of 1,000)
1st Quintile	704
2nd Quintile	684
3rd Quintile	666
4th Quintile	661
5th Quintile	655

Source: JD Power & Associates, Barclays Capital estimates.

Pending or Likely Regulatory Proceedings

Allegheny Energy (AYE)

West Virginia. We expect AYE's returns in West Virginia to improve by \$55 million in pre-tax margin by 2011 for a 9% ROE which would add \$0.20 per share. The company could file a base rate case in 3Q09 or 4Q09. As a reminder the last full rate case decision was in May 2007 when the company received a 10.5% allowed ROE on a 46.1% equity ratio.

On 7/10 the company filed for an interim fuel adjustment rider in West Virginia of \$82M. The company estimated first half 2009 under-recovery of \$82M versus \$137M estimated in last Fall's decision for the full year 2009. AYE requested a decision on interim recovery by October 1, 2009. AYE expects to file the annual fuel case by September 1, 2009 for rates effective January 1, 2010. We expect full or close to full recovery for AYE.

Pennsylvania. In Pennsylvania, West Power continues to procure power supply for the 2011–2013 period with the next auction results likely October 16 (a few days following the bidding). As planned this auction covers 1.8 MMwhrs. The average procurement price in the two auctions to date for residential customers is \$72.24/MWhr and for small and medium non-residential it is \$75.40/MWhr. So far 25% of a required 30.2MMwhrs has been procured. Overall, we have assumed AYE gets \$69.50/mwhr on 75% of its Allegheny Energy Supply output and \$44/Mwhr for the balance. Every \$1/MWhr overall at Allegheny Energy Supply is \$0.125/share.

Under a July 2008 order West Penn Power customers can phase-in a rate increase over 25% for three years. We do not expect rate-cap extension legislation to be enacted although there have been bills proposed which range from being repetitive of the rate mitigations plans in place to rate cap extension bills similar to those from 2008. Please see our passage on PPL Corporation for additional details.

PATH. The company has already received FERC approval which includes a 14.2% allowed ROE on the \$1.2 billion joint project with American Electric Power. Filings for approval have been made in Maryland, Virginia and West Virginia. In Virginia the PATH hearings are set for August 3-6 and the evidentiary hearing is January 9. We expect an outcome to this process by mid-2010.

Alliant Energy (LNT)

Iowa Power and Light Electric General Rate Case

Iowa Power and Light (IPL) filed its retail electric general rate case in Iowa on March 17, 2009 based on a 2008 historical test period. The key drivers for the filing include recovery of investments in reliability and emissions controls, anticipated increases in electric transmission service expenses, and retirement plan costs, known changes in retail electric demand, and expenditures associated with the 2007 winter storms and severe flooding in 2008. Rate changes are implemented in two phases with interim rates effective 10 days after the filing (March 27) and final rates effective approximately nine months later (if the

case is fully litigated). IPL is requesting an 11.4% ROE although interim rates will reflect the current allowed ROE of 10.7% on 49% equity on a rate base valued at \$1.875 billion. Also, \$84 million of the total \$171 million revenue increase request has been reflected in base rates effective March 27, 2009, subject to refund. The Consumer Advocate Division of the Department of Justice and any intervenors are scheduled to file testimony on or before July 17, 2009, with rebuttal testimony due on August 21. Assuming the case the case is fully litigated, a hearing is scheduled on October 5, with a decision and new rates implemented 1Q10. Settlement discussion will occur during the rate proceeding. Prospects of the settlement are unknown at this time, although Iowa has a demonstrated history of settlement in rate proceedings. The company plans to file another electric GRC early in 2010 with the same implementation timeframe, in order to recover \$425 million in wind and \$195 million in environmental controls. Should LNT not receive a transmission rider in the currently-pending GRC, this would also be a driver in next year's case.

Wisconsin Power and Light Electric and Gas General Rate Case

Wisconsin Power and Light (WPL) filed its retail electric/gas general rate case with the Public Service Commission of Wisconsin on May 8, 2009. WPL's filing is based on a 2010 forward-looking test year with a requested ROE of 10.6% on a 53.5% common equity component on an average rate base of \$1.362 billion (electric) plus \$0.212 (gas). WPL is seeking a total of \$91 million rate increase, comprised of an \$85 million retail electric increase and a \$6 million increase for gas service. WPL projects lower combined revenue deficiency in 2010 of \$133 million (11%) in present revenues. Drivers of WPL's rate request include \$36 million due to lower retail electric and gas sales, net of fuel, with the unrecovered portion of its revenue deficiency to come from continued cost reduction efforts and deferrals; \$30 million for return on CWIP related to Bent Tree Wind project; working capital of \$21 million and other of \$4 million. WPL expects new rates to be in place 1/1/2010.

Ameren (AEE)

Ameren filed their Illinois rate case on June 5 and we expect a filing in Missouri later this year both mainly to reduce regulatory lag. The combined IL electric request is \$181 million with a range of 11.75%–12.25% using a \$2.4 billion rate base for the test year ended 12/31/08. The combined IL gas request is \$45 million with a range of 11.25%–11.60% using a \$1.0 billion rate base. The filed capital structure calls for an equity content of 44%–49%.

AEE positioned the filing against a drop in the commodity side of the bill which has declined significantly since the last adjustment. Under the proposed electric increase the average IL residential electric customer will pay \$59–\$97 more per year (assuming 10,000 kWhrs) depending on the subsidiary and the average gas customer \$38–\$60 per year (assuming 785 therms). The savings from the latest electric supply adjustment is a \$100 savings per year for the average residential electric customer.

The IL filing is mainly to reduce regulatory lag and AEE comments that more than 77% (\$173 million) of the rate increase request relates to construction, operation and maintenance of the delivery system. The company's estimated 2009 IL ROE is 6% and every 1% is \$25 million pre-tax. Our EPS estimates are \$2.83 for 2009 and \$2.70 for 2010 with the IL utilities contributing \$0.53 in 2009 and \$0.60 in 2010. Guidance for the IL utilities is \$0.40–\$0.50 for 2009.

We also look for a filing from AEE in Missouri later this year to reduce regulatory lag and seeking a return on environmental investment. The company expects to underearn in Missouri in 2009 with a 7% ROE. As a rule of thumb a 1% change in ROE is worth approximately \$50 million of revenues in Missouri. We estimate that the company earns \$1.25 in Missouri relative to the company's range of \$1.15–\$1.25 for Missouri for 2009. The Missouri case filing will include a filing for the environmental rider which includes a recovery on investment that includes non-fuel operations and maintenance spending.

American Electric Power (AEP)

AEP East

Appalachian Power Company (APCo) has made its fourth environmental and reliability (E&R) filing in Virginia on May 15, covering the expenditures made in 2008. This filing asked for \$41.6 million, with recovery expected to begin in January 2010. Intervenor testimony is due on August 27, APCo testimony is due on September 10, rebuttal testimony on September 21, and hearings begin on October 1.

In West Virginia, APCo continues in its expanded net energy cost (ENEC) filing, which requested a \$156 million recovery in February 2008 before the West Virginia Public Service Commission (WVPSC.) The ENEC filing is essentially a beefed-up fuel filing that incorporates fuel, purchased power, off-system sales credits, etc., and should typically result in no change to earnings given that the filings simply seek to true-up the regulatory recoveries with actual incurred costs. An order is expected in this matter by September 30, 2009.

AEP continues to seek approval to build a 629 MW IGCC plant at its Mountaineer site in Mason County, West Virginia, although the current economic and credit market environment make this project a luxury not likely to be pursued even if approved. It currently stands in limbo in West Virginia, after being denied in Virginia. However, the carbon capture and sequestration (CCS) investment continues to move along at the current Mountaineer site, with AEP expecting operation by September 2009 on a 20-30 MW portion of the plant. If successful, the project would sequester 100,000–300,000 tons of CO₂ per year.

AEP's most important filing in Virginia was made on July 15 as APCo's rate case request was for a \$169 million revenue increase, based on 44% equity and a 13.35% ROE. The filing is preliminary, in our estimation, because APCo will likely have to adjust the rate case

test year and equity structure periods to reflect the ruling just handed down by the SCC related to Dominion's DVP subsidiary. We expect a modified filing by the end of the summer. Interim rates would be effective by December 12, 2010. With APCo's currently approved 10.2% ROE, actual earned ROE below 8% in 2008, and likely to be below 6% in 2009, there exists a good possibility of rate relief through this process. We expect the rate case will be effective for substantially all of 2010.

AEP West

AEP's Southwestern Electric Power (SWEPCo) unit filed a general base rate case before the Arkansas Public Service Commission (APSC) on February 19. The case (docket # 09-008-U) requested a \$53.9 million revenue increase premised upon \$608.9 million of rate base, a 35.68% equity structure, and an 11.5% ROE. The \$54 million increase includes \$28.7 million associated with a generation recovery rider. Rebuttal testimony is due on July 24th, staff and intervenor surrebuttal testimony is due on August 18, and sur-surrebuttal testimony is due on August 25. Hearings are slated to begin on October 20, with a final decision expected in December. Through 1Q, LTM earnings at SWEPCo produced about an 8.7% ROE.

SWEPCo is currently in construction on the J. Lamar Stall plant – a 508 MW combined cycle gas plant at its Arsenal Hill site. The site received its final regulatory approval from Arkansas in June. AEP estimates the plant will cost \$348 million, and be operational in mid-2010. SWEPCo also has been building the John W. Turk plant – a 600 MW coal plant in Arkansas. Construction began in late 2008, with a revised cost of \$1.6 billion (\$1.2 billion expected for AEP, which will own about 73% of the plant), and the plant was expected on-line in 2013. As with all coal-plant proposals, AEP has encountered continual resistance from several parties opposed to the plant. Most recently, and after losing a challenge in the Federal court system before the 8th Circuit, the Hempstead County Hunting Club is suing the APSC in an attempt to reverse the commission's approval of the plant. That challenge before the Arkansas Court of Appeals was successful, with the court revoking the permit granted by the APSC, citing poor procedures followed by both the APSC and SWEPCo. SWEPCo has announced it will appeal the ruling to the Arkansas Supreme Court. Dates around a final order are uncertain. It is continuing construction of the plant while the appeal proceeds.

An appeal of the air permit is also pending before the Arkansas Pollution Control and Ecology Commission, with hearings concluded in mid-June. Parties have until August 21 to file post-hearing briefs, with rebuttal briefs due by September 11. Following that – under an uncertain timeline that could take weeks or months – an Administrative Hearing Officer will make a recommendation to the Ecology Commission, which will then hear oral arguments and rule accordingly at one of its meetings. From that point, the ruling could then be appealed through the state court system in Arkansas. Final US Army Corps of Engineers approval is pending as well.

We expect the Stall plant will be built, but are less sanguine about the prospects for the Turk plant from here. Given AEP's multiple options for capital allocation, we don't see a meaningful impact on their ability to grow earnings by the 2%–4% they've guided to as a result of the Turk ruling.

AEP Ohio

In March, the Public Utilities Commission of Ohio (PUCO) ruled to approve an electric security plan (ESP) for AEP's Columbus Southern Power (CSP) and Ohio Power (OPCo) subsidiaries. The ruling allowed for average revenue increases of 7.5%, 6.5%, and 7% in 2009, 2010, and 2011, respectively. The ruling also allowed for clause recovery of fuel expenses, and explicitly included carbon-related costs within the fuel clause. Fuel balances in addition to the allowed rate increases outlined above will be deferred, with the balance (plus carrying costs) to be recovered from 2012–2018. The PUCO denied distribution rate increases outside of the gridSMART advanced metering program, anticipating that AEP Ohio will file a separate distribution rate case to address these other items.

On the matter of evaluating whether AEP and its peer utilities would pass or fail a significantly excessive earnings test (SEET) as laid out – but for which no specifics have been established – by legislation, the PUCO will convene workshops in the coming months. A decision on the matter is expected in mid-2010.

The ESP process is currently under appeal from both AEP Ohio and some intervenors. A ruling on the appeals is expected imminently, although we do not expect a material difference to the March order that would distort earnings expectations in a meaningful way.

AEP Transmission

AEP is involved in several active transmission projects, as outlined in Figure 30.

Figure 30: Summary of AEP Transmission Projects

Name	Length	Technology	Partner	Estimated Cost (in millions)	Expected In Service
Electric Transmission Texas (ETT)	N/A	345 kV	MidAmerican (50%)	\$400	2013
Prairie Wind	230 miles	765 kV	WR (50%) & MidAmerican (25%)	\$600	2013-2014
Tallgrass	170 miles	765 kV	OGE (50%) & MidAmerican (25%)	\$500	2013-2014
PATH-WV	275 miles	765 kV	AYE (50%)	\$1,200	2014
Pioneer	240 miles	765 kV	DUK (50%)	\$1,000	2015

Source: AEP Company Presentations

The ETT projects involved several short lengths of line, as well as substation upgrades, and so quantifying a distance is challenging. That said, of the projects that can be quantified in such a way, AEP is involved in over 900 miles of new construction, at a total cost of about \$3.7 billion. AEP's share of that cost should be about \$1.6 billion, suggesting a potential incremental \$0.15–\$0.20 of EPS between now and 2015. Looking further ahead, AEP is considering an additional 4,000–6,000 miles of transmission spending, by our estimates. If these projects were all to come to realization, it would represent an

additional \$0.80–\$1.00 of EPS. Understandably, the market has not been inclined to pay for this longer-term optionality, but we think it's clear that the market is also not currently pricing in even the currently active transmission projects in AEP's stock price.

CMS Energy (CMS)

CMS, under its Consumer's Energy subsidiary operates a regulated electric and a regulated gas utility within most of the state of Michigan excluding the "thumb" portion surrounding metro Detroit. All CMS's transmission assets were legally separated and then sold off. They now are owned by ITC Holdings, Inc. under that company's METC subsidiary.

Michigan Legislation

On September 18, 2008 the Michigan Legislature passed legislation that moved the state's regulatory structure away from a hybrid to a more fully regulated model. The legislation was subsequently signed by the Governor. The legislation instituted a renewable energy standard in the state of 10% by 2015 and institutes energy efficiency goals where program costs are fully recovered and incentives are awarded for beating targets. The cash collection from customers for these programs is collected at a level rate over 10 years while the revenues are booked as the costs are incurred allowing the company to over collect on a cash basis in the earlier years and under collect in the later years. Further, this mitigates rate shock and the need for continual rate increases by allowing the programs to go into place with a one time charge to customer bills.

Further legislation included a forward test year and a file and implement rule which allows for the self-implementation of rates 180 days after filing if no commission decision has been made. The self-implementation will then be modified and trued up or down with interest if it is not in line with what the Michigan PSC eventually approves within the 12 month statutory time limit. All of these measures will work to significantly mitigate regulatory lag, allowing the company to earn closer to its allowed ROE. The legislation also caps customer choice at 10% of load meaning infrastructure investments of significant size can be made with confidence that the customer base will be there in future years. Further, the legislation also created a Certificate of Need (CON) process where projects costing more than \$500 million are preapproved for recovery by the commission. Interest costs of the projects would be recovered during construction and the remaining costs would be recovered upon project completion.

Electric Rate Case

On November 14, 2008 the company filed an electric general rate case in Michigan under the laws passed in September referenced above. The requested increase was for \$214.5 million premised upon a regulatory accounting equity ratio of 40.88% applied to a 12 month average rate base for the period ending 12/31/09 of approximately \$6.3 billion. The requested allowed ROE was 11%. On April 27, 2009 the Michigan PSC staff recommended a revenue increase of about \$74.7 million premised upon a 12 month

average rate base for the period ending 12/31/2009 of about \$6.0 billion, an equity ratio of 40.51% and an allowed ROE of 11%.

While the headline metrics of the staff recommendation are generally in line with the company's request the operating expenses were where there were major differences. The staff, according to the company's statements on their first quarter earnings conference call, used some partial year data for 2008 capital expenditures and interpreted it as full year data. Furthermore, the staff had used historical expenditures and applied a CPI factor to them to project forward year expenses. This is in fact not representative of the amounts the company intends to spend on either an O&M or a cap-ex basis. Since the Michigan legislation calls for the use of a forward test year, and the final commission decision is not due or expected until November, three-quarters of actual data for the 2009 year will be available to determine how close actual numbers are in line with CMS's forecast versus the staff's recommendation.

Under the law in Michigan, consumer's can self-implement rates six months after a filing if no commission decision has yet been made. The Association of Businesses Advocating Tariff Equity (ABATE) of Michigan filed a motion with the commission which asked to have the self-implementation by the company stayed. The commission heard the motion and decided, according to the law that the self-implementation could go forward. After this ruling consumers self-implemented a \$179 million revenue increase versus the roughly \$215 million request, effective as of May 14, 2009.

Gas Rate Case

On May 22, the company filed a new gas general rate case in Michigan under the current law the company will be allowed to self-implement rates in six months, on or after October 22, 2009. This is important from a seasonal timing perspective as it will allow for new rates to go into effect prior to the next winter heating season. The rate increase request is required under the law to be adjudicated by the commission within 12 months, or by the end of May 2010. The request encompasses a \$114 million revenue increase, driven mostly by rate base growth and a declining sales forecast. Further, the return component of the revenue increase request is premised upon a 12 month average rate base for the period ending 9/30/2010 of approximately \$2.9 billion. Applied to this rate base were a regulatory accounting based equity ratio of 41.07% and a requested allowed return on that equity portion of 11%. Further, as part of the general rate case the company requested a sales decoupling mechanism, and automatic tracker mechanisms for both uncollectable and pension expenses. A prehearing was held before the Michigan Public Service Commission on June 24 2009 to set the schedule. The current schedule in the case calls for staff and intervenor testimony on October 22, 2009, rebuttal testimony on November 16, 2009, and hearings schedule for the weeks of December 14, 2009 and January 4, 2010. The current targeted date for a final decision is May 22, 2010.

Constellation Energy (CEG)

In Maryland Constellation Energy lost its appeal on July 2 of the Public Service Commission's decision to initiate a public interest review of the proposed nuclear joint venture with Electricite de France as it was found to be premature. We expect an outcome later in the schedule of the public interest proceeding where the PSC has agreed to take action on the case by September 17 which would be consistent with the company's closing timeline. To close the transaction approval is also required from the Nuclear Regulatory Commission. Hearings begin August 19 and end August 25.

Figure 31: Schedule for Public Interest Review of Proposed CEG/EDF Nuclear JV

<u>Date</u>	<u>Action</u>
August 5	Reply Testimony due from parties other than CEG, BG&E, and EDF
August 13	Rebuttal testimony filed by EDF, CEG, and BG&E and served on other parties
August 14	Discovery requestes due on rebuttal testimony
August 17	Responses to post-rebuttal testimony due
August 19-25	Hearings
September 2	All parties file briefs

Source: Maryland Public Service Commission

According to the June 22, 2009 *Baltimore Sun* article "Deal Merits Scrutiny," the State sent CEG a settlement proposal on June 2 seeking "short and long-term rate relief, a commitment to green technologies, ring-fencing to protect BGE from Constellation's speculative financial dealings, and elimination of an \$87 million compensation package for Constellation's CEO". We expect a reasonable outcome to be reached as we expect that the State along with the Commission support the transaction.

In the event the transaction does not go through we expect Baltimore Gas & Electric to file a rate case. We do not assume a rate case in our forecast currently which is an 8% ROE in 2010 (\$1.83 billion in equity) on an estimated \$3.7 billion in electric and gas distribution rate base at year-end 2010. If the 2010 earned ROE was a more reasonable 10%, we calculate it would be \$0.19 per share accretive to our \$3.54 EPS 2011 EPS estimate.

Consolidated Edison (ED)

ConEd NY Electric

On May 8, ED filed for a three-year electric rate plan proposing level annual rate increases of \$695 million effective April 1, 2010, 2011, and 2012, respectively. The filing reflects an 11.6% ROE and equity ratio of 48.2% on a rate base valued at \$15.6 billion (as of March 2011), \$16.9 billion (March 2012), and \$18 billion (March 2013). The filing also includes an alternative proposal for a one-year \$854 million increase, reflecting a 10.9% ROE, including property taxes of \$127 million, additional operating costs of \$153 million, carrying charges on additional infrastructure \$237 million, increased pension/benefit costs of \$114 million and an increased ROE of \$127 million. The company is requesting continuation of decoupling and current recovery provisions for pension/benefits, property taxes, long-term debt and environmental remediation. ED is seeking regulatory deferral if certain expenses exceed 4% annual inflation rate if the actual

ROE is less than authorized. This filing also reflects \$30 million of "austerity" measures (see discussion below pertaining to the NYPSC's prior year GRC decision for ConEd NY electric), continuing through March 31, 2011. We expect NYPSC Staff response to the GRC on August 28, 2009.

On May 26, 2009 ED filed for rehearing of the New York Public Service Commission's (PSC's) April 24 electric rate case decision for ConEd NY. In that order, the PSC authorized ED a \$523.4 million or 7.2% rate increase, premised on a 10% ROE and 48% equity component of capital on a \$14.097 billion rate base effective retroactively to April 1, 2009. The Commission also authorized the company to collect an additional \$1998 million beginning May 1, related to a recent change to Public Service Law that raises an existing 0.2% revenue tax by an incremental 1.8% on a temporary basis. The approved base rate revenue requirement reflects a \$60 million imputed adjustment for "austerity" measures imposed. If the full \$60 million of cost savings are not achieved, ED will be able to petition the PSC to defer that portion of the austerity revenue adjustment, up to \$30 million, for recovery at a later date, following the first year of new rates. In addition, the Commission adopted a 2% productivity factor adjustment to the company-proposed test year labor expense level, versus ED's proposed 1% factor. This determination reduced the revenue requirement by an additional \$11 million. ED's request for rehearing focuses largely on the arbitrary and unprecedented nature of the aforementioned austerity imputation, arguing that it is..." without basis in the record, at odds with policies adopted by other agencies and governments...and inconsistent with the long-term interests of New York State."

In conjunction with the rehearing request, ED submitted a plan outlining the steps it proposes to take to meet the austerity requirements of the PSC's order. However, the company has indicated this filing should not be construed to indicate agreement or acceptance of the Commission order. The measures to be implemented include reductions in: labor costs (\$6.5 million); corporate expenses such as travel, attendance at professional conferences, communications costs, industry association membership fees (\$7.4 million); capital projects, and operations and maintenance costs (\$33 million); and, other unidentified cost reductions (\$13.1 million). There is no established timing or process for this rehearing request at this time.

On May 14, 2009, the NYPSC issued a separate generic order requiring the state's major electric and gas distribution utilities to submit for PSC consideration austerity plans within 30 days. These plans are to address current and future company actions that can reduce or postpone discretionary expenses. Should the PSC rule on rehearing to revoke the austerity provisions of the order, or if this provision is ultimately overturned in the courts, the Commission could required ED to file a plan under the generic ruling, thereby effectively imposing similar requirements.

We also expect ConEd NY to file a gas GRC this year, with new rates effective October 2010.

Orange and Rockland Utilities, Inc.

ED subsidiary Orange and Rockland filed a \$17.8 million gas delivery rate increase on November 26, 2008, effective November 1, 2009. The increase is based upon an 11.6% ROE and 48% equity on a rate base valued at \$261.8 million. On March 27, 2009 the NYPSC Staff recommended that the Commission authorize a \$10.1 million rate increase based upon a 10% ROE and 48% equity component of capital on a \$275.8 million rate base. O&R's most recent gas rate decision came in October 2006 when the PSC adopted a three-year rate settlement providing rate increases of \$12 million, \$0.7 million, and \$1.1 million on November 1, 2006, 2007, and 2008, respectively. These increases ultimately were levelized with the use of deferred accounting, whereby increases of \$6.5 million were authorized in each of the first two years, with an additional increase of \$1.8 million authorized in year three.

On June 30, 2009, Orange and Rockland, Staff of the Department of Public Service, the Consumer Protection Board, USG Corporation, and the Small Customer Marketer Coalition filed a Joint Proposal with the Commission in Orange and Rockland's gas base rate case. The Joint Proposal sets forth a settlement of all outstanding issues in this case. The only active party in the case not joining in the Joint Proposal is the Town of Ramapo. The Joint Proposal, which is subject to the review and approval of the Commission sets forth a three-year gas rate plan (November 1, 2009 through October 31, 2012) for the company. The Joint Proposal provides for gas rate increases of \$12.8 million, \$5.2 million and \$4.5 million effective November 1, 2009, 2010 and 2011, respectively. Alternatively, the Joint Proposal gives the Commission the opportunity to phase in the base rate increase as follows: \$8.964 million effective November 1, 2009, \$8.964 million effective November 1, 2010, and \$4.626 million (in addition to a one time collection of \$4.338 million through the Monthly Gas Adjustment) effective November 1, 2011.

The Joint Proposal also contains the following major items:

- An assumed annual return on common equity of 10.4%;
- Reconciliation of actual pension and other post-retirement benefit expenses, environmental remediation expenses, property taxes, long-term debt costs and certain other expenses to amounts reflected in rates;
- Deferral of carrying charges for distribution infrastructure investments to the extent actual expenditures are less than amounts reflected in rates;
- Company may defer carrying charges on up to \$2 million of annual incremental interference related spending;
- Deferral of increases in certain expenses above a 4% annual inflation rate, but only if the actual annual return on common equity is less than 10.4%;

- Implementation of a revenue decoupling mechanism using “revenue per customer” methodology under which actual energy delivery revenues would be compared, on a periodic basis, with the authorized delivery revenues with the difference accrued, for refund to, or recovery from, customers, as applicable; In the first rate year (November 1, 2009–October 31, 2010), as an austerity measure, the company will implement a 2% productivity adjustment (i.e., 1% above the normal 1% productivity adjustment). Statements in support of/in opposition to the Joint Proposal were submitted July 13, 2009. A hearing to consider the Joint Proposal has been scheduled for July 28, 2009. The Commission is expected to consider the Joint Proposal in October 2009.

Dominion Resources (D)

Dominion Virginia Power (DVP) has made five filings before the Virginia State Corporation Commission (SCC) seeking a net increase of \$316 million in revenues, to be effective between July 1, 2009 and January 1, 2010. The filings and effective dates are listed below:

Figure 32: Dominion Regulatory Filings

Request	Amount (in millions)	Effective Date
Fuel	(\$236)	1-Jul
Base Rates	\$298	1-Sep
Transmission	\$78	1-Sep
Bear Garden	\$77	1-Jan
Virginia City Hybrid Energy Center	\$99	1-Jan
Total	\$316	

Source: Company and regulatory filings.

The base rate case filing sought a 13.5% ROE on 52.8% equity at the March filing, but the capital structure DVP sought was as of the end of 2010. In a subsequent ruling, the SCC decided that DVP’s capital structure would be set as of year-end 2008. This should effectively limit DVP to a 47-48% equity ratio. On about \$8.5-9.0 billion of rate base, this equates to about \$0.09 to \$0.10 of lower possible increase. In addition, the rest of the rate case filing will be amended based on a Sept. 2010 test year, as opposed to the 27-month forward period DVP had planned to utilize. We would expect this to impact the rate base request. The amended filing is due before the SCC by August 3. The ROE mechanism established by Virginia law obliges the state to have a floor set by the majority of DVP’s peer utilities in the Southeastern US using a three-year rolling average. The base rates would become effective before the final order is due, subject to refunds. The procedural schedule for that filing doesn’t have hearings until January 2010 (see below). A positive note subsequent to the recent SCC rulings noted above on rate case test periods is the clarification that DVP may file a rate case at any time in the future if it feels an economic incentive to do so. Previously, the understanding was that DVP would be unable to file a

rate case for another two years. This mitigates some of the impact of the earlier test periods we described above.

The Virginia City Hybrid Energy Center, a 585 MW fluidized bed coal plant under construction in Wise County, Virginia, is designed to be carbon capture compatible. The plant is scheduled to cost \$1.8 billion, excluding financing costs, and should be completed in 2012. Consistent with the overall requests in the rate case described above, DVP is seeking a 14.5% ROE for the plant, comprised of the 13.5% ROE request in the rate case, plus a 100 bp adder that is allowable through a separate rider under the re-regulation bill that applies to new coal plants.

The Bear Garden facility is a 580 MW combined cycle plant to be located in Buckingham County, Virginia, that was approved by the SCC in March 2009. Similar to the Virginia City plant above, DVP requested a 13.5% ROE with a 100 bp adder for combined cycle plants, raising the all-in request to a 14.5% ROE. This plant is expected to cost \$619 million, and should be completed in 2011.

The \$78 million transmission increase is the result of requesting a transmission rider (Rider T) to encompass current and future transmission adjustments, and is net of a \$227.3 million revenue requirement, offset by a \$149.4 million reduction in base rates as the transmission component is removed. This increase was approved by the VA SCC and will be effective September 1.

Timing for the above open matters is outlined in Figure 33.

Figure 33: Dominion Open Regulatory Matters

Case	Subject	Dates
PUE-2009-00016	Revision to fuel factor	July 9 - comments due July 16 - hearings scheduled
PUE-2009-00017	Establish Rider R for Bear Garden Generating Station	August 4 - comments due August 11 - hearings scheduled
PUE-2009-00011	Adjustment to Rider S for Virginia City Hybrid Energy Center	August 11 - comments due August 18 - hearings scheduled
PUE-2009-00019	Revision to base rates	January 13, 2010 - comments due January 20, 2010 - hearings scheduled

Source: Company Regulatory Filings

In November 2007, Dominion filed a combined operating and construction license (COL) with the NRC for a third unit at its North Anna nuclear site. The COL was based on using GE's Economic Simplified Boiling Water Reactor (ESBWR) design. D has since re-opened its selection process for a technology at the site, and the search is ongoing. It is our belief that D will be in the first wave of new regulated nuclear construction, and to that end, we expect a decision on a design partner to be reached by year end.

DPL, Inc. (DPL)

Ohio Retail Rate Matters

On February 24, 2009 DP&L filed a Stipulation Agreement with the Public Utility Commission of Ohio (PUCO) on its Electric Security Plan (ESP), filed October 10, 2008, as required by SB221. The Stipulation was signed by the PUCO staff, the office of the Ohio Consumers Counsel, and other intervening parties and among other things, extends DP&L's existing rate plan through 2012, adjusts its fuel recovery mechanism beginning in 2010, and provides for the recovery of certain SB221 compliance costs. On June 24, the PUCO unanimously approved DPL's pending ESP Settlement. The approved plan establishes rates through 2012 and implements a fuel recovery mechanism beginning next year. In addition, DPL will be able to continue to retain 75% of the benefits derived from its coal optimization strategy in 2010 and beyond. The plan further stipulates that an excessive earnings test will not be applied until 2013.

As a member of PJM, DP&L incurs costs and receives revenues from the RTO related to its transmission and generation assets, as well as its load obligations for retail customers. SB221 included a provision that would allow Ohio electric utilities to seek and obtain a reconcilable rider to recover RTO-related costs and credits. On February 19, 2009, the PUCO approved DP&L's request to defer costs associated with its transmission, capacity, ancillary service and other PJM-related charges incurred as a member of PJM. On March 28, 2009 DP&L filed for recovery of these RTO-related costs. Through this filing, DP&L proposes to eliminate seven retail riders related to transmission and ancillary services and replace them with a single retail rider that would incorporate all charges and credits from the RTO as well as the amounts approved for deferral. This new rate was approved on May 27, 2009 and went into effect June 1, 2009.

DTE Energy (DTE)

Detroit Edison

On January 26, 2009 DTE's electric utility subsidiary Detroit Edison filed a rate case, their first under Michigan's new regulatory legislation. The new legislation introduced a number of constructive regulatory concepts including a fully forward test year, file-and-implement rate-making, pre-determination on large scale projects, limits on customer switching, and a more clearly articulated plan for renewable construction and spending. All of these constructs, when combined, help Edison to substantially mitigate the affects of regulatory lag, placing the utility in a surprising secure situation with the promise of supportive regulation always in the background.

The power of a forward test year is demonstrated impressively in Edison's case as they are able to recover sales declines in their service territory prospectively. As the electricity supplier to Detroit's "Big 3" automakers, one can imagine that Edison's forecast of an approximate 8% decline in sales (sales expectation is 49,165 GWhs for the July 2009–June 2010 period, down from the 53,600 GWhs currently embedded in rates and corresponding to \$164 million in lost revenues) is a definite possibility. While sales declines thus far in 2009 are trending close to in-line with company guidance (down 6%

for the 2009 calendar year at last update) we are watching closely to see how much of the \$164 million ask is actually implemented when Edison begins their interim rates on July 26, 2009. In addition to the sales declines (which, in our view, will be very difficult for the commission to argue with), we believe that Edison will likely recover all of the costs associated with increased pension, employee benefit, and bad debt expenses, while the company will likely get more pushback on its request for recovery of inflation and rate base changes, and in all likelihood will be disallowed the revenues associated with the increased ROE request and O&M tied to incentive compensation.

The procedural schedule for Edison's rate case started becoming more active in July, with Staff and intervenor testimony taking place on July 9, 2009, and with rebuttal testimony planned for July 30 (shortly after Edison's likely date of implementation on July 26, 2009), while a final order from the commission will come by January 26, 2010 at the absolute latest (Michigan's legislation mandates that commissions must rule on rate cases within one year of the original filing, or rates automatically become effective). On June 26 Edison took the first step in beginning their implementation when they filed with the MPSC their intention to implement \$280 million in interim rates. While details around what specific components make up this amount continue to be vague, we feel that it represents a reasonable jumping off point for the company and a good place to begin discussions with the commission. The staff recommendation that came out on July 9 2009 was well below expectations, with the staff recommending a rate reduction of ~\$4M, with an allowed ROE range of 10.5% - 11.0% (Edison is currently allowed an 11.0% ROE). While the recommendation was surprisingly low, we believe that many of the staff's assumptions, in particular their sales forecast, will be found by the commission to be substantially off point.

After rates are finalized by the commission (most likely in January 2010), we expect Edison to continue filing rate cases back to back until sales declines begin to taper off, which, in our view, is unlikely to happen until after the 2011 rate case cycle in a best case scenario. As a result, Edison will be in perpetual rate case cycle for the foreseeable future, with the payoff of this typically negative scenario being that Edison's exposure to weakness in the Michigan economy will be limited to the six months immediately following a filing (until they are allowed to implement interim rates).

MichCon

While MichCon has been absent from the regulatory front since mid-2005 (due to rate moratoriums among other things), the DTE gas utility filed a case on June 9, their first under Michigan's new legislation. MichCon's total ask was \$193 million, with rate base additions accounting for the bulk (\$83 million) of the increase, while increases in company use and lost gas (\$36 million), a new uncollectible tracker (\$33 million), lower sales (\$15 million), O&M (\$16 million), and a higher ROE (11.25% versus the 11.0% authorized being \$10 million of the request) making up the balance of the request. We will also be watching closely the discussions around the decoupling mechanism that MichCon included in the filing.

Consistent with the electric regulation in Michigan, we expect that rates will be implemented on an interim basis in January 2010, with a final order expected by June 2010.

Renewables, Efficiency, and Conservation Programs

DTE has the benefit of a customer surcharge that will begin to flow in September 2009. This \$3–\$4 per month per customer charge allows DTE's utility subsidiaries to have access to the necessary capital in order to meet many of their efficiency and environmental mandates, and without the cost that would come from traditional debt issuances. We view this as very constructive for DTE.

In addition to the regulatory mechanisms that were introduced with the recent legislation, it has long been believed that Michigan is very consciously moving in the direction of full decoupling on the gas and electric distribution front. While fellow Michigan regulated utility CMS Energy is expected to handle decoupling in a separate regulatory filing, it is our expectation that DTE will address the decoupling issue in their next set of rate cases (MichCon included a decoupling mechanism in their June 2009 filing and Detroit Edison's expected January 2010 filing will again address the issue).

Duke Energy (DUK)

Duke Energy Carolinas

Duke Energy Carolinas (DEC) filed a rate case on June 2, 2009 with the North Carolina Utilities Commission (NCUC), and expects rates to be effective January 2010. The filing seeks a \$496 million increase in revenues, premised upon 53% equity and an 11.5% ROE. DUK is actually seeking a 12.3% ROE through the case, but has established its revenue request off of the 11.5% level. These amounts are based off a \$9.854 billion rate base request.

DUK's Save-A-Watt program was approved via a rider mechanism, subject to refund, in North Carolina. The full issue, including amount of recoveries and the future mechanisms, will be handled through the recently filed rate case.

DEC also expects to file a rate case in South Carolina sometime this summer, with rates expected to be in effect by January 2010.

DEC filed a combined operating and construction license (COL) with the NRC in December 2007 for two new AP 1000 nuclear reactors at the William States Lee site in Cherokee County, South Carolina. Before construction (not expected to begin in earnest until at least 2012), DUK is seeking both a legislative outcome in North Carolina that would allow for better security around the recovery process, as well as a partner in construction to ease the financial and risk burden of the project. These are the early stages of the process, and we do not expect DUK will have a new plant built until closer to 2020.

Duke Energy Ohio

In Ohio, Duke Energy has largely resolved the electric security plan (ESP) process that replaced the previous rate-setting system in Ohio when the Public Utilities Commission of Ohio (PUCO) issued its finding in December 2008. Pending final appeals to the Ohio Supreme Court by the Ohio Consumers' Counsel – which we do not expect will be successful – the order allows a generation rate increase of 1.9%, 2%, and 1.2% in 20'09, 2010, and 2011, respectively, and allows for recovery of environmental spending and fuel costs, as well as provides DUK the opportunity to formulate its Save-A-Watt demand response system for further study.

DUK also filed a distribution rate increase in July 2008, which resulted in a settlement between DUK and some parties to the matter that was filed on March 31, 2009 that would result in a \$55.3 million rate increase (versus an \$86 million original request.) The stipulation also allows DUK to begin a small weatherization and energy efficiency program in Ohio. The settlement was approved by the PUCO on July 8, and includes the \$55.3 million increase referenced above, based on a 10.63% ROE.

In Indiana, DUK is awaiting a ruling from the Indiana Utility Regulatory Commission (IURC) on its energy efficiency process. Settlements have been reached with all intervenors except the Citizens Action Coalition of Indiana. A ruling from the IURC is expected in summer 2009.

DUK also continues progress toward building its Edwardsport Generating Station – a 630 MW IGCC in Indiana. The latest cost estimate of \$2.35 billion was approved by the IURC in January 2009, along with approval for DUK to begin work on a carbon capture study. Construction work on the IGCC has begun, and the plant is expected to be completed in 2012.

Edison International (EIX)

Southern California Edison (SCE) operates under a long-term cost of capital decision put in place by the California Public Utilities Commission (CPUC), and the current decision stands until January 2011. A new cost of capital case would be expected to be filed in April 2010. The current metrics allow for a 48% equity structure, and an 11.5% ROE. In addition, the California utilities are able to adjust their costs based on moves in the relevant Moody's bond index (the Baa index for SCE). As has been noted several times since the ruling was made last year, utilities are able to adjust their ROE by 50% of the move in the benchmark if the benchmark moves by more than 100 bp. For SCE, the next adjustment period occurs in September.

SCE's last rate case was decided in March 2009, with a new case not expected until fall of 2010 for implementation in January 2012. Based on the results of both the cost of capital and rate case proceedings, SCE's projections for rate base and capex are below.

Figure 34: SoCal Edison Regulatory Projections

SCE Rate Base

(\$ in millions)

	2009E	2010E	2011E	2012E	2013E
Base Case	\$14,500	\$16,200	\$18,100	\$20,800	\$23,000
Low Case	\$14,200	\$15,800	\$17,200	\$18,800	\$20,500

Source: Company presentations.

SCE Capex

(\$ in millions)

	2009E	2010E	2011E	2012E	2013E
Base Case	\$3,400	\$3,900	\$4,200	\$4,400	\$4,300
Low Case	\$2,800	\$3,200	\$3,500	\$3,700	\$3,600

Source: Company presentations.

California has fairly progressive energy efficiency and conservation guidelines in place, and has authorized an incentive structure for the three-year periods from 2006–2008 and 2009–2011. This structure allows for a 9% incentive earning on the value of energy efficiency savings if SCE meets 85% of its goal, and 12% if it meets 100% of its goal. There are progress payments along the way, and the total awards or penalties for meeting or falling short of the goals is capped at \$200 million. SCE's goal for the 2006–2008 period was a \$1.2 billion savings to customers, which could result in a maximum \$146 million pre-tax payment to the utility. The first progress payment, for the 2006–2007 period, was made in December 2008 in the amount of \$25 million. SCE expects to receive a \$14 million–\$26 million second progress payment through rates in 2010 (with the decision expected in 4Q09.) While the rulemaking in this regulation is still fairly fluid, SCE does expect it will receive the full amount of any incentive earnings for the 2006–2008 period by the end of 2010, with the CPUC making a decision in December 2009.

SCE has been approved to deploy about 5.3 million smart meters between 2008 and 2012 through its SmartConnect advanced metering program. The latest total project costs are estimated at \$1.7 billion, with \$1.25 billion of that amount going into rate base. Consistent with the strengthening trend that we're seeing with demand response and conservation efforts, SCE estimates that this program may shave 1,000 MW of peak demand from its system once fully implemented. Coupled with the 1,000 MW of load that SCE currently shaves through its existing programs, SCE aims to reduce up to about 10% of its peak load through these demand response programs.

California law compels utilities to procure 20% of their electricity via renewable resources by December 2010. SCE does not expect to be able to meet this standard, despite being able to take advantage of built-in flexibility in the methodology that includes rolling over of any past surpluses and the presumption of current renewable energy deliveries that it may roll forward into the current period. There is a maximum \$25 million penalty that the CPUC may assess in the course of reviewing the annual compliance filings that SCE and its peer utilities are required to make. It is unclear at this point how this situation will develop, but SCE doesn't believe it will be made to pay a penalty for its 2008 procurement.

In mid-May, SCE stated that it would not seek to build the Arizona portion of the Devers-Palo Verde 2 (DPV2) line that has been proposed for the last few years. The matter would have required a re-filing of the application with the Arizona commission, and in our view success seemed unlikely. SCE will continue to build the California portion of the line that runs from Palm Springs to Blythe, CA. The Arizona portion of the line was expected to cost \$304 million, with the California portion estimated at \$723 million. The California piece should be completed by 2013.

Entergy Corporation (ETR)

ETR is in the midst of a proposed spin-off of its nuclear business, which has been named Enexus Energy. They obtained NRC approval last summer, and that approval expires on July 28, 2009. Enexus will likely seek an extension of the approval at that point, and we do not anticipate any problems. The spin was also approved by the FERC in June 2008, and that approval remains in effect for a reasonable amount of time. The spin has been hampered by pending regulatory approvals from Vermont and New York states, as well as a tight credit market that would weaken part of the investment case for the spin.

In Vermont, there are two items pending: approval for a re-licensing of the Vermont Yankee (VY) nuclear plant, as well as approval for the license transfer that would authorize the spin. The VY license expires in March 2012, and the Vermont Public Service Board (PSB) and the Vermont legislature have roles to play in any relicensing decision. The legislature will have to grant authorization to the PSB to consider the extension, and then the PSB may decide the situation on its merits. At this point, the legislature has not granted the PSB that authority. The legislature has been unfavorable toward VY in the recent past, seeking to require ETR to fully fund its future decommission liabilities at the present time – only to have that bill vetoed by the governor. Further, there is a material anti-nuclear atmosphere in Vermont that creates an air of uncertainty. Ultimately, we believe the plant will be relicensed, provided ETR is willing to replace the current power purchase agreement (PPA) that expires at the end of the current license period, with a new one that runs along with the extended life of the plant. The license transfer step that is required for Enexus to take ownership of the plant is awaiting a final determination, with all necessary steps having been completed for months. Again, we believe if an agreement can be reached regarding a future PPA, the rest of the process will unfold favorably.

In New York, the parties involved in the spin-off matter have been in various stages of settlement discussions since December 2008, with no resolution having been reached yet. The state Public Service Commission (NYPSC) process had its last milestone in October 2008, when the ALJs hearing the matter ruled that an adequate record to reach a decision had been reached. If there is no settlement, the ALJs will submit a recommendation to the NYPSC, which could then rule at its discretion.

Entergy Arkansas (EAI)

The 2008 storm cost recovery efforts were begun in January 2009, while early 2009 storms led to further costs incurred at EAI estimated at \$120 million–\$140 million. The

Arkansas Public Service Commission (APSC) has allowed EAI to defer 2008 storm costs and to seek recovery via the storm damage rider. Given the unfavorable results of the 2006–2007 rate case in Arkansas, where EAI requested a \$106.5 million increase, and was instead granted a \$5.1 million rate reduction, the storm recovery process that is currently ongoing should serve as a decent barometer of the relationship between the APSC and EAI.

EAI has also sought APSC approval to spend \$631 million on environmental upgrades at its White Bluff coal plant. In order to comply with state and federal regulations by 2013, EAI is hoping to begin construction by 4Q09. EAI is asking for an APSC ruling by September 25, 2009.

Entergy Texas (ETI)

The Public Utilities Commission of Texas (PUCT) recently approved a unanimous settlement on March 11 that would increase base rates by \$46.7 million, and which stipulated a 10% ROE as reasonable (the settlement was black box, and thus made no specific mention of an allowed ROE.) The rates were effective as of January 28, 2009. Separately, ETI had been seeking permission to either remain in the SERC region, or join ERCOT, as part of its transition to competition plan. The Texas legislature, before adjourning on June 1, passed SB 1492, which pertained to ETI's membership in qualified power regions, and its transition to competition. This effectively forecloses a transition to competition for the next four years, and authorizes ETI to withdraw its current filings before the PUCT to that effect.

Also, ETI filed for \$577.5 million of storm costs, and made its filing before the PUCT on April 21. Consistent with state law, the PUCT has 150 days to rule on the amount of recovery and on securitization. Recent staff recommendations would allow all but \$3 million of this amount. A settlement conference is slated for July 27, with a hearing to be held on August 3.

Entergy Gulf States Louisiana (EGSL)

EGSL is estimating that it incurred between \$240 million–\$255 million in storm costs associated with Hurricanes Ike and Gustav. Current legislation in Louisiana allows for securitization of storm costs, and EGSL should be making a filing soon. In addition, the commission staff's review is ongoing for EGSL's formula rate plan (FRP) filing totaling \$26.8 million for revenue increases and capacity costs.

Entergy Louisiana (ELL)

ELL had been in the process of repowering its Little Gypsy plant under a dual-fuel (pet coke and coal) process using a circulating fluidized bed technology, until the recent drop in natural gas price, coupled with economic downturn, called into question the near-term economics of the \$1.76 billion project. Following an earlier ruling from the Louisiana Public Service Commission (LPSC), ELL recommended a long-term suspension of longer than three years for the project. In late April, the LPSC agreed, while awaiting the next filing from ELL/EGSL which is due by June 20, regarding future claims and next steps regarding

recovery. We think the process bears watching because ELL should, in our view, be able to recover investments already made in the project, despite the recent long-term postponement. In fact, this case serves as something of a test case for state commissions' willingness to repay utilities for approved investments that have been subsequently cancelled or delayed.

ELL is also in the middle of a storm cost recovery proceeding, following damage incurred by Hurricanes Ike and Gustav. The company estimates storm damages of about \$390million–\$405 million, and expects to begin a recovery filing shortly. As noted above with respect to EGSL, existing law in Louisiana already permits securitization of storm costs.

Finally, test year 2006 and 2007 FRP filings are still under review by the LPSC, with a final ruling in the 2006 test year issues expected later this summer.

Current allowed ROEs for each of ETR's regulated subsidiaries are below:

Figure 35: Entergy Allowed ROEs by Subsidiary

Company	Authorized ROE	2008 Actual ROE
EAI	9.90%	3.4%
EGSL	9.9% - 11.4%	10.9%
ELL	9.45% - 11.05%	9.8%
EMI	9.46% - 12.24%	8.9%
ENO	11.1% (electric) 10.75% (gas)	16.5%
ETI	10.00%	6.4%

Source: Company filings, Barclays Capital estimates.

Exelon Corporation (EXC)

PECO

The rate cap transition period ends for EXC's PECO and ExGen subsidiaries on December 31, 2010. PECO filed a default service program and rate mitigation plan (DSP) in September 2008, and the Pennsylvania legislature passed Act 129 in October 2008. Act 129 prescribes a 15 year transition to smart meters, as well as requiring an energy efficiency and conservation (EE) plan be filed by July 1, 2009. The EE plan requires a 1% reduction in the expected June 2009 – May 2010 load by May 2011, and 3% reduction by May 2013. The Act specifies that costs associated with the EE plan not exceed 2% of 2006 revenues (which were about \$5.2 billion for PECO). A plan for implementing smart meter rollout must be filed with the PA Public Utility Commission (PAPUC) by August 14, 2009.

Mindful of requirements found in Act 129, the PAPUC approved a settlement with PECO on April 16, 2009, that allowed for a 29-month term beginning January 1, 2011, and ending May 31, 2013. Under the agreement, PECO will participate in nine procurement processes between June 2009 and May 2013, with a variety of short- and long-term

contracts. The settlement also allows for certain customers to phase in rates. Finally, the settlement allows for residential and small consumer classes of customers to pre-pay their expected rate increases through 2010, accruing interest at 6%, and then having them applied to their bills in 2011 and 2012. The first RFP process has been held already, with a result for the 17- and 29-month products of \$100–\$102/MWh, which we believe equates to about \$88/MWh to the winning generation bidders when subtracting items such as line losses and PA gross receipts taxes. The remaining auction schedule, along with products up for bid at each auction, is shown in Figure 36.

Figure 36: Exelon PECO Procurement Schedule

Event	Product(s)	Bids Due	PAPUC Decision
Fall 2009	Full Requirements & Block Energy	9/21/2009	9/23/2009
Spring 2010	Full Requirements & Block Energy	5/24/2010	5/26/2010
Fall 2010	Full Requirements & Block Energy	9/20/2010	9/22/2010
Spring 2011	Block Energy Only	5/23/2011	5/25/2011
Fall 2011	Full Requirements & Block Energy	9/19/2011	9/21/2011
Spring 2012	Block Energy Only	4/16/2012	4/18/2012
Winter 2012	Full Requirements Only	1/18/2012	1/20/2012
Fall 2012	Block Energy Only	9/17/2012	9/19/2012

Source: NERA Economic Consulting, www.pecoprocmnt.com.

PECO operates under an electric rate freeze until 2011, and we don't anticipate a distribution rate filing there until the post-2010 issues have been clarified.

ComEd

ComEd has a formula rate filing before the FERC to true up its transmission costs; in that filing they requested a \$16 million reduction in rates.

Regarding an electric distribution case, which ComEd would typically be on schedule to file later this year, the company plans to defer that filing while it observes what kind of financial position it is in following the announced O&M and capex cuts it made earlier this year. A filing is possible in early 2010, but nothing is planned at this point. ComEd earned a 3.3% ROE, according to company filings and our estimates, in 2008. The company was allowed a 10.3% ROE in its last rate case in Illinois, which was awarded in September 2008.

FirstEnergy (FE)

We look for FE to file a market rate option (MRO) in Ohio in 4Q09. This would cover the June 2011–May 2013 power procurement for the utilities. We look for the company to propose two to three auctions this time to layer-in pricing as opposed to the single auction for June 2009–May 2011. The process can last 275 days and would conclude in 4Q10.

FPL Group Inc. (FPL)

Florida Power & Light (FP&L)

FP&L filed a rate case in mid March, seeking \$1.25 billion over 2010 and 2011. The case requests a \$1 billion increase in rates for 2010, with an additional \$250 million in 2011. These amounts are premised upon a 2010 test year, and a 55.8% equity structure and 12.5% ROE. It is worth noting that FP&L also requested a reduction in its fuel costs for 2010 that would result in a drop of about \$2 billion in expense to ratepayers – more than offsetting \$1 billion of increase that's been requested for 2010. The rate case should have rounds of testimony and rebuttal testimony in through August, with hearings scheduled for August 24–28 and September 2–4. A staff recommendation is expected in late October, and a commission vote is expected in November, with rates to be effective for January 2010.

FP&L is also asking for a \$150 million storm reserve accrual, which it hopes to build to a \$650 million level over time. The company is seeking a continuation of its generation base rate adjustment (GBRA) mechanism to reflect the expected addition of the West County #3 unit in mid-2011.

NextEra Energy Resources

There are a couple of regulatory or legislative developments that are relevant for the NextEra piece of the business. In Texas, NextEra has been approved to build a 250 mile 345 kV transmission line as part of the CREZ transmission build-out in the state. The project is expected to cost \$600 million, and represents FPL's first regulated transmission build outside of Florida (through a new unit called Lone Star, LLC, which is a subsidiary of FPL Group Capital). Lone Star needs to file for its Certificate of Convenience and Necessity in Texas; hearings are expected in 1Q10, with a final ruling likely later that year. Construction is slated for 2011.

As has been noted numerous times lately, FPL and its peers in renewable energy development look to be beneficiaries of the renewable titles in the American Recovery and Reinvestment Act of 2009 (aka the stimulus bill). The bill would allow wind generation access to the investment tax credit (ITC) that's helped solar energy shave 30% off the capital costs of a project, provided a company has the tax capacity to enjoy it (otherwise the benefit is deferred until it can be used). It would also create an ITC-like grant that would offer a check from the government for 30% of capital costs, payable about 60 days after the unit goes into service, regardless of tax appetite. The rules for parceling out these benefits are expected to be codified by July, and bear watching for anyone interested in renewable energy development.

Great Plains Energy (GXP)

On September 5, 2008, GXP filed rate cases for each of its subsidiaries in all jurisdictions (Kansas City Power and Light in both Missouri and Kansas, and Greater Missouri Operations in Missouri). The cases have not been carried out without surprises. On the positive side, the Kansas staff came out with a ROE well ahead of expectations for KCP&L,

but the lower equity to total cap ratio that was suggested more than outweighs the increase in allowed ROE. In Missouri, the staff recommendations were, as expected, very negative, but the settlements that were announced were definitely positive surprises, in terms of how close to the agreed upon amount was to the original ask and the fact that settlements were agreed upon in the first place. The fact that is worth noting, is GXP's increased revenue requests in September 2008 were premised upon an off-system sales margin based on a gas deck and power prices that are 20%–30% below current levels. Due to regulatory rules that forbid an increase in a company's ask beyond the original request, it is likely that GXP will be subjected to material regulatory lag until the next set of rate cases are filed and the company is trued up to a power environment that more accurately reflects the current situation.

While the settlements were definitely steps in the right direction, they are partially offset by delays associated with bringing latan 1 back in-service, causing GXP to ask for one month extensions of their true-up deadlines in both Missouri and Kansas, and effectively knocking back the expected dates for their final orders and delaying the associated rate relief benefits. In conjunction with the revised procedural schedules, GXP issued releases to the financial community with the expected earnings impacts. Management stated that Kansas would be a \$0.07 EPS hit in 2009 (but they expected this entire amount would be offset by additional cost cuts) and Missouri's delay would be a \$0.10 EPS hit.

Figure 37: GXP Rate Case Summary

Rate Case	Company Request (\$ in Millions)			Staff Recommendations (\$ in Millions)			Settlement Details (\$ in Millions)
	Total	ROE	Equity Ratio	Total	ROE	Equity Ratio	Total
GMO - MPS	\$66.0	10.75%	53.82%	\$46.0	9.75%	51.03%	\$48.0
GMO - L&P	\$17.1	10.75%	53.82%	\$22.8	9.75%	51.03%	\$15.0
GMO - Steam	\$1.3	10.75%	53.82%	\$1.0	9.75%	51.03%	\$1.0
KCPL - MO	\$101.5	10.75%	53.82%	\$52.9	9.75%	50.65%	\$95.0
KCPL - KS	\$71.6	10.75%	55.39%	\$53.9	11.40%	50.76%	\$59.0

Notes: Amounts and ROE range for MO based utilities is based upon mid-point of Staff's Recommendation

Source: Company filings and presentations.

The settlements that were announced in Missouri defied what has been the status quo for GXP and the Missouri regulators. The terms were a modest concession on GXP's part (relative to the original ask) in both cases. For KCP&L, the company's initial ask was for \$101.5 million, and the settlement was for \$95 million (\$10 million of which will be treated as additional amortization), while GMO originally asked for \$83.1 million and got \$63 million in the settlement. While the settlements are still waiting approval, it is our view that the commission is likely to accept the agreements. The fact that GXP was able to settle at all in MO is a step in the right direction and bodes well for the upcoming round of cases to be filed in 2010.

While the three main cases in Missouri (KCP&L-MO and MPS/L&P's (GMO)), announced settlements in April and May, respectively, KCP&L KS announced their settlement on June

18 2009. As has already been articulated, a settlement is almost always considered to be a more desirable outcome when looked at relative to the fully litigated alternative, making GXP's handling of their regulatory situations in Missouri and Kansas that much more important and impressive. However, these regulatory successes are partially offset by lapses on the execution side, as was shown by the delays in getting Iatan 1 to meet the commission's standard to be included in rate base. As a result, the rate case process for the outstanding cases was delayed about a month. Rates from the settlement are expected to be effective on September 1, 2009 in Missouri and on August 1 2009 in Kansas.

Shortly after implementation in these cases, we expect KCP&L Kansas to file their final rate case (that was set out by the Comprehensive Energy Plan) during 4Q09, with filings expected for the Missouri subsidiaries during the early portion of 2010. This next set of rate cases is of particular importance due to Iatan 2 flowing into rate base (assuming that construction remains on schedule and the plant is placed in-service during the summer of 2010 as expected). In addition, this next round of cases promises to be filled with some tough issues around cost over-runs associated with Iatan 2, and improper spending around Iatan 1's environmental retrofits (a component of the recently filed settlements stated that during the next round of rate cases, up to \$30 million of KCP&L-MO's rate base \$15 million of GMO's can be challenged and disallowed if deemed imprudent by the commission). Final orders and effective rates for the next round of rate cases are expected, in our view, during 3Q/4Q for Kansas and in the beginning of 2011 in Missouri. We expect staff testimony for the more important Missouri rate cases (about 70% of the company's rate base) sometime during the summer to early-fall time period. A staff decision typically signals the trough valuation for a regulated utility, and it is at this time (pending valuation) that we would be most compelled to look at becoming more aggressive on GXP.

Hawaiian Electric Industries (HE)

HE subsidiary, Hawaiian Electric Company (HECO), filed a general rate case on July 3, 2008, requesting a \$97 million or 5.2% electric rate increase based on an 11.25% return on equity (54.3% of capital) on a rate base valued at \$1.4 billion for a 2009 calendar test year. (This requested increase was in addition to an interim increase that was authorized by the Hawaii Public Utilities Commission on October 22, 2007 in the company's 2007 test-year electric rate case proceeding awaiting a final PUC decision for which there is not statutory deadline. The interim increase in the 2007-test-year case was revised on May 1, 2008, to \$77.9 million from an initially authorized \$70 million.)

In the 2009 test-year proceeding, HECO requested that \$73.1 million of the increase be implemented on an interim basis "as soon as "practicable" and the remaining \$23.9 million be implemented upon the commercial operation of the company's Campbell Industrial Park (CIP) generating facility (for which the expected in-service date was August 2009 at the time of filing). In addition to the costs of the CIP facility, HECO indicated that the proposed rate increase reflected capital investment needed to maintain and improve system reliability, and higher operation and maintenance and depreciation expenses.

In April 2009, the consumer Advocate filed testimony, recommending a \$62.7 million or 3.4% permanent increase, based on a 9.5% to 10.5% ROE on a rate base valued at \$1.259 billion that included the CIP facility.

On May 15, 2009 HECO, the Consumer Advocate, and the Department of Defense (but excluding Commission Staff) filed a settlement in the pending 2009 test year electric rate case, calling for HECO to be authorized a \$79.8 million (6.2%) interim rate increase, premised on a 10.5% ROE on an average rate base valued at \$1.253 billion. The settlement agreement represented a negotiated compromise of the parties' respective positions and was approximately 18% lower than HECO's original request of a \$97 million increase in revenues. Under the terms of the settlement, HECO would have been permitted to establish a revenue balancing account (decoupling mechanism) that would have allowed the company to adjust revenues for the differences between actual and authorized revenues. The settlement also reflected inclusion of the company's CIP facility in rates, for which HECO had originally proposed to reflect in a second-step increase. The remaining issues among the parties impacting the amount of the increase for the proceeding related to the appropriate test year expense amount for informational advertising, and the appropriate return on common equity for the test year. This settlement also excluded the requested revenue adjustment mechanism or tracker for operations and maintenance expense and capital expenditures, that was also proposed by HECO, to minimize regulatory recovery lag. This request is now part of a separate docket, which will be considered at a later date.

On July 2, 2009 The Hawaii Public Utilities Commission issued an order partially approving and partially rejecting the aforementioned settlement agreement on interim rates. As a result of the PUC's modification to the settlement, HECO expects that the interim increase ultimately authorized will be \$61.1M. The PUC's order requires HECO to exclude from rate base any costs associated with the Campbell Industrial Park facility. The settlement had reflected inclusion of the CIP facility in rates, whereas the company had originally proposed to reflect the facility in rates in a send-step increase. The order also excluded the costs associated with the stipulated employee incentive wage increases, and requires the update of certain transmission and distribution and maintenance costs to reflect current commodity prices. The order further excludes certain stipulated cost items associated with the Hawaii Clean Energy Initiative from base rates, because these initiatives are still the subject of pending PUC proceedings and have not yet been approved.

In addition, the PUC rejected the terms of the agreement calling for HECO to implement a decoupling mechanism which would have allowed the company to adjust revenues for the differences between actual and authorized revenues through the establishment of a revenue balancing account. In its decision to deny the implementation of such a mechanism, the PUC stated that it was considering the issue of decoupling in the context of a separate proceeding, and that "it has not yet determined that a sales decoupling mechanism and the establishment of HECO's proposed revenue balancing account are just and reasonable". The PUC opined that the "parties disregarded the Commission's directive" as it had

explicitly advised the Parties to not include any mechanisms or expenses related to programs or applications that have not been approved by the commission, such as decoupling, the renewable energy initiatives program and advanced meter reading. The Commission added that such programs are in the early states of the regulatory approval process, and that the PUC "cannot reasonably determine that the programs will be implemented during the test year."

The Consumer Advocate and the Department of Defense had the opportunity to file comments on HECO's calculated interim increase amount within five days. The interim decision will be implemented after the PUC issues a decision on HECO's calculations. If the amounts collected pursuant to an interim decision exceed the amount of the increase ultimately approved in the final D&O, then the excess would have to be refunded to HECO's customers, with interest.

The procedural schedule for the remainder of the case includes testimony responding to HECO's revised filings as a result of the PUC's ruling are to be filed by July 20, and hearings on the unresolved issues scheduled to begin on August 10. There is no statutory time limit within which the PUC must issue a decision regarding permanent rates.

Maui Electric Company, Inc. (MECO)

On March 20, 2009, MECO filed a Notice of Intent to file an application for a general rate increase on or after May 29, 2009 (but before June 30, 2009) and a motion requesting PUC approval to use a 2009 calendar year test period for the upcoming rate case. The filing of this general rate increase application in accordance with the Energy Agreement, under which the parties agreed that MECO would file a 2009 test year rate case to implement a decoupling mechanism. On April 27, 2009, the PUC issued an order denying MECO's motion and stating that MECO may elect to file its rate case application with either a split 2009/2010 test period or a 2010 calendar test period, pursuant to the PUC's rules. Under the rules, MECO (and HELCO, discussed below) would be allowed to file rate cases with 2010 test years on or after July 1, 2009.

Hawaiian Electric Light Company, Inc. (HELCO)

In order to implement the decoupling mechanism committed to by the parties in the Energy Agreement, the parties agreed that HELCO would file a 2009 test year rate case. In light of recent PUC action denying MECO's motion for approval to use a 2009 test year (see MECO discussion above), HELCO is evaluating the timing of its rate case filing.

Decoupling Proceeding

In the Energy Agreement (described below), the parties agreed to seek approval from the PUC to implement, beginning with the 2009 HECO rate case interim decision, a decoupling mechanism, similar to that in place for several California utilities, which decouples revenue of the utilities from kWh sales, and provides revenue adjustments (increases/decreases) for the differences (shortages/overages) between the amount determined in the last rate case and(a) the current cost of operating the utility as deemed

reasonable and approved by the PUC, (b) the return on and return of ongoing capital investment (excluding projects included in a proposed new Clean Energy Infrastructure Surcharge), and (c) changes in tax expense due to changes in State or Federal tax rates. The decoupling mechanism would be subject to review at any time by the PUC or upon request of the utility or Consumer Advocate. On October 24, 2008, the PUC opened an investigative proceeding to examine implementing a decoupling mechanism for the utilities. In addition to the utilities and the Consumer Advocate, there are five other parties in the proceeding. On March 30, 2009, the utilities and the Consumer Advocate filed their joint proposal and initial statement of position and the other parties filed their initial statements of position. The utilities' and Consumer Advocate's joint proposal is for a decoupling mechanism with two components: 1) a sales decoupling component via a revenue balancing account and a revenue escalation component via a revenue adjustment mechanism and 2) an earnings sharing mechanism. Final position statements of the parties were submitted in May 2009. The Commission noted in its July 2, 2009 order that the sales decoupling mechanism and establishment of the proposed RBA are in the early stages of the regulatory approval process, and that it cannot reasonably determine that the program will be implemented during the test year.

Hawaii Clean Energy Initiative

In January 2008, the State of Hawaii and the U.S. Department of Energy (DOE) signed a memorandum of understanding establishing the Hawaii Clean Energy Initiative (HCEI). The stated purpose of the HCEI is to establish a long-term partnership between the State and the DOE that will result in a fundamental and sustained transformation in the way in which energy resources are planned and used in the State. HECO has been working with the State, the DOE and other stakeholders to align the utility's energy plans with the State's plans. On October 20, 2008, the Governor of the State of Hawaii, The State of Hawaii Department of Business, Economic Development and Tourism, the Division of Consumer Advocacy of the State of Hawaii Department of Commerce and Consumer Affairs, and HECO, (on behalf of itself and its subsidiaries, HELCO and MECO) signed an Energy Agreement setting forth goals and objectives under with HCEI and the related commitments of the parties. The Energy Agreement provides that the parties pursue a wide range of actions with the purpose of decreasing Hawaii's dependence on imported fossil fuels through substantial increases in the use of renewable energy and implementation of new programs intended to secure greater energy efficiency and conservation. Many of the actions and programs included in the Energy Agreement will require approval of the PUC in proceedings that will need to be initiated by the PUC or the utilities.

On June 25, Gov. Linda Lingle signed into law House Bill 1464, which, among other initiatives, increases the renewable portfolio standard targets for utilities operating in the state. Renewables now must comprise 25% of each utility's resource portfolio by December 31, 2020, and 40% by December 31, 2030. Previously, the law had required that renewables comprise 10% of each utility's resource portfolio by December 31, 2010, 15% by December 31, 2015, and 20% by December 31, 2020. H.B. 1464 requires that up to 50% of the RPS targets may be met by renewable energy displacement technologies such as solar water heating, or energy efficiency and

conservation programs. Under the new law, renewable displacement technologies and energy efficiency and conservation programs would count towards meeting the RPS through December 31, 2014; however, beginning January 1, 2015, the law establishes that these means would no longer count toward meeting the RPS targets. Importantly, the law allows the Hawaii Public Utilities Commission the authority to revise the RPS. H.B. 1464 also establishes energy efficiency portfolio standards, mandating that utilities achieve 4,300 GWH of electricity usage reductions by 2030, with additional interim goals to be established by the PUC. The law states that, beginning in 2015, energy usage reductions brought about by renewable energy displacement technologies will count towards meeting the efficiency standards. The bill requires that the commission establish incentives and penalties for meeting such standards and grants the PUC the authority to adjust the standards.

NiSource(NI)

Gas Distribution Cases

NI, due to its conglomerate status, is consistently involved in the rate case process in at least one of their jurisdictions. While some of these (in particular, Bay State Gas in Massachusetts) have some importance from an earnings standpoint (if full ask of \$34.6 million is received, 2010 EPS could have as much as \$0.04–\$0.05 of upside), many (Columbia Gas of Kentucky) are not of particular significance due to the minimal potential positive upside (entire increase that NI is asking for is about \$11.6 million). Final orders are expected in Bay State's and Columbia Gas of Kentucky in November 2009 and March 2010, respectively. In addition to these two outstanding cases, NI's Columbia Gas of Pennsylvania subsidiary could file during 4Q09 or 1Q10.

NIPSCO

NI's regulatory story is dominated by the NIPSCO electric subsidiary and their outstanding rate case that was initiated August 29, 2008. The case takes on particular significance due to NIPSCO's absence from the regulatory process for over 20 years. Furthermore, NIPSCO historically has over-earned their allowed ROE, and this, when coupled with a service territory that has substantial industrial (and steel in particular) exposure, makes for a controversial proceeding. Asking for a rate increase during a profoundly deep recession always makes a rate case more challenging.

NIPSCO is asking for a one-time increase of \$85.7 million (revised down from a \$105 million total increase that was to be carried out in two steps) premised upon a 49.9% equity to total capital structure and a 12.0% ROE. Not surprisingly, the testimony and recommendations made thus far by the intervenors has been very negative, with the Indiana Office of the Utility Consumer Counselor recommending a revenue reduction of \$135 million, predicated upon a 10% ROE and a 39.2% equity to total cap structure. We don't believe that a result of this magnitude is likely, however the prudent approach, in our view and what we have currently reflected in our estimates, is a flat result for the rate case.

Hearings and additional testimony picked back up recently, with the company's rebuttal testimony on June 26 while additional hearings are planned for July 27, 2009. A final decision and effective rates are expected during late 2009, but more likely early 2010.

Northeast Utilities (NU)

Northeast Utilities is composed of four main subsidiaries, three of which are divided across business lines for transmission and distribution/generation. These are Western Massachusetts Electric Company (WMECO), Public Service Company of New Hampshire (PSNH), and Connecticut Light & Power (CL&P). The fourth subsidiary is a gas utility company in CT, Yankee Gas (Yankee). Each electric subsidiary is regulated at the state level for its distribution or generation (NH only) and at the federal level by the Federal Energy Regulatory Commission (FERC) for its transmission assets. Transmission is filed on a project by project incentive basis at the FERC. We do not expect any regulatory rate filings at Yankee Gas provided the strong growth from the expansion plans at that subsidiary continues.

Transmission

Under the FERC NU's transmission assets at the three relevant subsidiaries are allowed a 12.89% return on equity on the New England East West South Projects (NEEWS) and a 13.10% return on equity on other transmission which qualifies for the incentives under the FERC rate structure. The 13.10% ROE is composed of a 10.40% base ROE, to which is added the following:

- A 74 bp increment which began on 10/31/06 for higher bond yields;
- A 50 bp incentive for regional transmission organization (RTO) membership;
- A 46 bp technology adder if approved for underground portions, etc.; and
- A 100 bp adder for projects entering service post 2004 but prior to 1/1/09.

The 46 bp adder is determined on a project by project basis, and the 100 bp adder post 1/1/09 will also be reviewed by the FERC on a project specific level. We believe the vast majority of NU's transmission projects will qualify for the 100 bp adder while the 46 bp technology adder will be more project dependent.

The FERC has outlined what it sees as criteria, some of which a project must meet for consideration of incentives. The project must be: non-routine, reduce congestion or ensure reliability, large in size, require significant financing, be multi-state, be multi-pool, be multi-company, and/or be technologically advanced.

Non-Transmission

A breakdown of current regulation and expected rate filings by subsidiary is provided in Figure 38.

Figure 38: Summary of NU Regulation by Subsidiary

Subsidiary	Allowed ROE	Expected Distribution Rate Filing	Adjustment Mechanisms/Trackers			
			Fuel & Purchased Power	Electric Transmission Costs	Stranded/ Transition Costs	Pension Tracker
CL&P	9.40%	Late '09/Early '10	x	x	x	
PSNH Dist.	9.67%	Filing Made Spring '09	x	x	x	
WMECO	8% - 12%	Mid - 2010	x	x	x	x
Yankee Gas	10.10%	No Plans	x	n/a	n/a	

Source: Company Presentations

PSNH

On April 17, 2009 PSNH filed a temporary rate increase request with the Public Service Commission of New Hampshire (NH PSC). The generation side of the business is regulated at the state level with trackers and a set ROE somewhat similarly to federal transmission regulation. The temporary increase requested \$36.4 million in annualized revenues to be effective on August 1, 2009. Subsequently, the company filed a notice of intent with the commission stating that they would file a new rate schedule on or before July 1, 2009 that would constitute a \$51 million rate increase. The company would request rates effective as of August 1, 2009 and as is typical in New Hampshire the rate increase would be suspended by the commission pending a full general rate case review. This full GRC review would be expected to last about a year. The rate case metrics attached to either requested increase were not made public as of this writing; however, according to earlier projections by the company, we would expect the year-end average rate base to be about \$774 million for distribution assets and about \$389 million for generation assets. The NH PSC could grant both the temporary increase and a further increase, dependent upon the result of the full GRC review, or they could deny the temporary increase and merely adjudicate the full GRC. The company currently is regulated under a decision rendered by the commission on May 25, 2007 which allowed a \$50.1 million rate increase (+4%), which was premised upon a year-end 2005 average rate base of about \$668 million, a 47.66% equity ratio, and a 9.67% return on equity.

CL&P

The company has stated publicly that given current economic conditions that the anticipated rate case filing in CT would be delayed from mid-year 2009 to late year 2009 or early in 2010. We do have concerns around regulation in CT given the recent decision for a separate company, United Illuminating, in that state. To briefly review that case, in November 2008, United Illuminating requested a \$52.4 million revenue increase premised upon a rate base of about \$511 million, a 10.75% return on equity and a 50% equity ratio. In February 2009, the CT Department of Public Utility Control (DPUC) approved a rate increase of \$6.1 million, premised upon a rate base of about \$499 million, and equity ratio of 50% and a return on equity of 8.75%. After the rate order United Illuminating announced plans to cut capital expenditures by \$50 million after which

the CPUC and the CT Attorney General Richard Blumenthal became concerned over how this cut would impact reliability. The Attorney General filed a petition on May 18 with the DPUC asking the commission to review whether United Illuminating violated the order by reducing O&M expenses. United Illuminating then filed a petition with the DPUC saying the Attorney General's request was without factual support, and that the brief period of reduced expenditures would not impact reliability. The DPUC has stated that it wants to monitor capital and operating expenditure levels going forward.

In our view, the United Illuminating situation remains worth watching going forward and the 8.75% return on equity is a concern. If the economy recovers by early 2010 with CL&P is expected to file a better outcome may be in store in that rate case given less political pressure at that time. Based upon the company's projections as of this writing CL&P's rate base at the end of 2009 will be \$2.351 billion and at the end of 2010 will be \$2.557 billion.

WMECO

We anticipate that WMECO will file a rate case in mid-2010, the projected rate base at the end of 2009 is expected to be \$410 million and at the end of 2010 \$434 million. WMECO currently operates under an allowed ROE range of 8%–12% with tracked expenses as outlined above.

NSTAR (NST)

A seven-year rate settlement was approved by the Massachusetts Department of Public Utilities (DPU) on 12/30/05. The settlement includes annual inflation-adjusted distribution rate increases that began on January 1, 2007 and continue through 2012. These increases are generally offset by an equal and corresponding reduction in transition rates. The current rate plan incorporates a deferral mechanism for transition costs that are expected to be recovered over the 2010–2013 timeframe. The amount could approach \$250 million in 2010. A 10.88% carrying charge is earned on the average balance. A 50%/50% earnings sharing mechanism is triggered if NSTAR Electric's ROE exceeds 12.5% or falls below 8.5%. NSTAR Electric can initiate a rate proceeding if the ROE falls below 7.5%.

The Green Communities Act was enacted on July 2, 2008 by the Massachusetts Legislature and the DPU issued its Decoupling order on July 16, 2008. The act covers solar installations, encourages long-term renewable energy contracts, requires implementation of a smart grid pilot program, establishes a Renewable Portfolio Standards (RPS) goal for the state of 15% by the year 2020, and requires the pursuit of all cost-effective energy efficiencies. The DPU's plan is to phase in a decoupling model between now and 2012. Utilities that are operating under a rate agreement can continue to do so, but for all incremental energy efficiency spending, NST will be able to recover any lost base revenues and earn performance incentives on that spending. NST filed a plan with the DPU for 2009 in December 2008 and has since filed a three year plan.

Transmission Initiatives Update

NST's base transmission ROE is set at 11.64% with the opportunity to earn an additional 100 bp on new construction projects. NST's approximate transmission rate base is \$750 million. The company completed a second and final phase of a major underground transmission project in 2008, at a total cost of about \$300 million. NST expects 2009 transmission expenditures to be about \$100 million.

On May 21, 2009, NST and Northeast Utilities (NU) announced that the FERC ruled favorably on the proposed structure of a transmission arrangement that interconnects New England with the Canadian province of Quebec. FERC approved the participant-funded transmission line between New England and Quebec, and the assignment of firm transmission rights to Hydro-Quebec (HQ) to enable HQ to deliver low-carbon hydroelectric power into New England. The new tie line will use high voltage direct current (HVDC) technology to connect HQ's hydroelectric system and New England's 345-kV system in south central New Hampshire. This will provide approximately 1,200–1,500 mW of import capability into New England at a total cost of an estimated \$700 million to \$800 million, including NST's share of \$200 million. Construction will likely take place in the 2011–2014 timeframe. This corresponds well with NST's current rate plan (described above) which incorporates a deferral mechanism for transition costs that are expected to be recovered (cash) over the 2010–2013 timeframe, including an approximate \$250 million in 2010.

NV Energy (NVE)

NVE Energy is the largest utility in the state of Nevada and has two main utility subsidiaries, Sierra Pacific Resources in the northern portion of the state and Nevada Power in the southern portion of the state, whose service territory includes Las Vegas. Both subsidiaries market under the NV Energy name, and the company changed its name and stock symbol from Sierra Pacific Resources (SRP) to NV Energy (NVE) in the past year. Similarly, the two utility subsidiaries at the company whose legal names remain Sierra Pacific Power Co. in the north and Nevada Power Company in the South are now referred to as NV Energy North and NV Energy South.

Under current law in Nevada fuel and purchased power are trued up on a monthly basis and the Commission uses a hybrid test year that adjusts for known and measurable changes. Nevada Power is currently in with a rate case before the Public Utility Commission of Nevada (PUCN) and a decision was made by the commission on June 24 and rates became effective on July 1.

Nevada Legislature

In the just completed legislative session in Nevada the legislature passed some changes to utility regulation in the state. NV Energy North will file their next rate case no later than the first Monday in June 2010, and NV Energy South will file their next rate case no later than the first Monday in June 2011. Holding to the 210 day statutory limit within NV for deciding a rate case the rates from each filing will become effective, subject to Public

Utility Commission of Nevada (PUCN) approval, on January 1 of the year following the filing. Further, the PUCN will be allowed under the new law to allow deferral of rate implementation upon the request of a utility and is allowed to implement low income customer rates. The renewable portfolio standard was increased from 20% to 25% by 2025. The amount of the standard that must come from solar generated power was increased from 5% to 6% of the RPS by 2016. Procurement of power from outside the state will now also be allowed to count against the standard. Further, the commission is now authorized under the new law to develop and adopt regulations allowing for utilities to recover energy efficiency impacts.

Nevada Power

On February 27, 2009, as required under the hybrid test year structure Nevada Power filed a revised request for \$305.7 million versus their original request of about \$324 million made in December 2008. The revised filing is premised upon a rate base of just over \$5.0 billion, an equity ratio of 44.15% and a return on equity of 11%. The Staff recommendation was issued on April 14, 2009 and called for a \$202.8 million revenue increase on a rate base of just under \$4.6 billion, an equity ratio of 44.15% and a return on equity of 10.5%. The subsidiary currently earns a 10.7% return on equity which is what we model going forward. On June 18, 2009, Commissioner Sam Thompson issued a draft order calling for a \$218 million revenue increases premised upon a \$4.7 billion rate base, a 44.15% equity ratio, and a 10.4% return on equity. The key difference between the request and the staff rec/proposed order other than the ROE was a disallowance of CWIP in rate base related to the Harry Allen plant. The company is earnings neutral to this outcome as they will book AFUDC on this CWIP going forward. There will be a cash lag related to this, however.

The draft order would de-skew rates from non-residential customers to residential customers. Residential rate increases from this de-skewing will be mitigated as the increase would coincide with a reduction in the Base Tariff Energy Rate (BTER) for fuel costs to take place on January 1, 2010. NPC's revised request called for a residential customer rate increase of 16.7%, and the commission draft order calls for a rate increase of 9.3% (12.3% with the de-skewing). With reductions to the BTER the net increase to customers from the draft order would be 6.8%. To further mitigate rate shock the commission draft order calls for a phase-in of rates in two stages. The first stage would be a 3% increase on 7/1/09 and the second increase would be for the balance of the increase of 3.8% (6.8% estimated net of the BTER less the 3% implemented on 7/1/09) and will occur on 1/1/10. The company will book revenue as though the entire rate increase had occurred on 7/1/09 and hang the cash to revenue difference on the balance sheet for future recovery.

The final order was approved by the PUCN on 6/24 and was slightly better than the draft decision. The commission approved a \$222 million revenue increase premised upon a \$4.7 billion rate base, a 44.15% equity ratio and a 10.5% return on equity.

PG&E Corp. (PCG)

PG&E Corp. is a large utility that serves northern California including San Francisco. The company is currently operating under a three year rate order which will expire on 1/1/11. As a result the company will be filing a General Rate Case later this year for rates to be effective on 1/1/11. We would expect that the next General Rate Case will call for a three year forward rate schedule which would take account of attrition and rate base growth over time. PCG operates in CA under nearly full sales decoupling and all energy procurement costs are passed through. Further the company operates under a multi-year cost of capital mechanism with an adjustor, if triggered, and has significant precedents in place at the California Public Utilities Commission (CPUC) related to pension recoveries. As of this writing pensions were 83% funded and the 2006 settlement with the CPUC allowed for contributions of \$176 million per year through 2010. Regulatory accounting allows the use of a balancing account to neutralize pension related earnings impacts, and a balancing account is used should cash contributions rise above \$176 million annually. The one major item which does get tracked in some other jurisdictions which is not tracked in California is uncollectables expense. There are several different regulatory activities set to occur for PG&E Corp. beginning later this year and throughout 2010. We detail them below.

Cost of Capital Mechanism Filing

The current cost of capital adjustment mechanism operates through the end of 2010. The mechanism sets an initial return on equity and then allows for that ROE to be adjusted on a once a year basis should a bond index move by more than 100 bp. If the mechanism were triggered in this way the ROE would be adjusted up or down by half of the move in the index. The index is measured annually from October to September each year. The company then makes an advice filing at the CPUC indicating the move in the reference bond index and the calculated ROE adjustment, if applicable. We would anticipate this advice filing is made in mid-October. There is some disagreement over which Moody's Bond index should be used as the reference index as the CPUC regulations in the mechanism do not specifically address how to treat a split rated company. However, for Edison International, the CA utility subsidiary of EIX, which is also split rated, the lower rating was applied. This is important as so far the Moody's Baa Bond Index is above the 100 bp trigger level while the Moody's A Bond Index is still below the trigger by about 40 bp. It is our view that the Baa Index will be applied this fall.

Since the ROE adjustment mechanism is only in place through 2010, another filing has to be made in the spring of 2010, likely in April, for the Cost of Capital mechanism which will be in place in 2011 and beyond. This will open the issue of whether the multi year ROE adjustment mechanism is kept or whether CA reverts to annual Cost of Capital proceedings as was done in the past. It will also allow for the potential adjustment to the allowed capital structure, which is now 52%. We expect the company to file for a multi year mechanism in April and a decision to be made by the CPUC on this matter by December 2010.

Energy Efficiency Incentives

The Energy Efficiency Incentives in California are awarded using a look back mechanism. The utility gets to book a portion of the award on an annual basis using a one year look back and after a three year "cycle" gets to book the remainder of the award by looking at the performance over that entire three year period. The company received 35% of the calculated 2006 and 2007 incentives amid debate at the CPUC over how to measure the direct impact of PG&E's programs and what portion of overall efficiency gains those programs were directly responsible for. The CPUC plans a full review of the 2006–2008 cycle by year end 2009 and completion of the true-up for the three year period by year-end 2010.

The 2009–2011 cycle is also under review at the commission with a full review of the entire mechanism under way. The CPUC has indicated that the avowed goal of the proceeding is to make the process transparent and simplified. Although there has been some opposition to the energy efficiency awards voiced in the CA Assembly, we expect some sort of long term award mechanism to be put in place by year-end 2009.

Electric General Rate Case

The current general rate case under which the utility operates terminates in January 2011. Therefore the company will file a new GRC before the CPUC. A notice of intent, which will contain the majority of the details of the filing will be made in August 2009, with the filing of the first application occurring in November 2009. Testimony would be expected to be filed in December 2009 with litigation occurring throughout 2010. Third party filings and company responses will occur in the spring, hearings will likely be held in the summer with a final decision by year-end. The CPUC has been later than this on some decisions in the past but if that delay occurs rates would be made retroactively effective to 1/1/11. In our view the process would stretch no further than March of 2011. The commission under the CA statutes will have 30 days after an ALJ decision is rendered to issue a final order.

FERC Transmission Rate Orders

In California transmission rate base is regulated by the FERC at the national level. This rate base currently earns a 12% return on equity versus the 11.35% return on other assets as awarded by the CPUC. The FERC sets this return in an annual filing with the commission which the company makes every August for a decision in approximately 12 months time. This timeline gets extended somewhat if there is a prospect for settlement which has occurred the last couple of years. The last decision was Transmission Order 10 in which the company asked for a \$760.5 million revenue requirement and received a \$718 million revenue requirement under a settlement in October 2008. Transmission Order 11, in which the company requested \$849 million has reached a settlement which has been filed with an ALJ at FERC, a final decision is anticipated in 3Q09. Transmission Order 12 will be filed at the FERC on or about August 1, 2009.

Other Items

In what amounts to a very full regulatory year, the company will also file their next Gas Accord in the second half of 2009 with a decision likely by 3Q10 and will file their compliance filing with regard to meeting California's renewable portfolio standard (RPS) of 20% on August 1, 2009.

PNM Resources (PNM)

PNM Resources operates an integrated electric utility in New Mexico, PNM Electric (PNM-E) and an T&D utility in Texas, Texas New Mexico Power (TNMP). On May 28 the New Mexico Public Regulatory Commission (NM PRC) approved a staggered \$77.1 million revenue increase for PNM-E that will take place in 2009 and 2010. As part of the order the company is prohibited from any rate increases until March of 2011. The New Mexico Legislature also passed a forward test year into law under which PNME's next rate case, presumably filed in 2010 for rates effective after March of 2011 will be filed under. As of this writing it is difficult to say what the timing and structure of the next PNME rate filing will look like.

TNMP

TNMP has an ongoing rate case in Texas which was filed by the company on August 29, 2008 requesting \$8.7 million in revenue increases. An amended request was filed on March 31, 2009 which increased the requested revenue increase to \$24.4 million or +16%. The request was updated for Hurricane Ike interruption costs, as Texas law now allows for such recovery, and a higher cost of debt. The amended request is premised upon a \$430 million rate base, a 40% equity ratio, and a requested return on equity of 11.25%. About \$6 million of the differential between the original and the amended request results from increasing cost of debt (from 7.14% to 9.43%), another \$5.1 million is resultant from a proposal to recover \$20.6 million in Hurricane Ike related costs over the next five years.

On June 3, 2010 the Public Utilities Commission of Texas (PUCT) Staff issued a recommended order of a \$7.6 million revenue increase premised upon a rate base of just under \$430 million, an equity ratio of 40% and a return on equity of 10.33%. The \$7.6 million recommended increase includes a \$5.0 million storm allowance per Ike, a \$1.1 million transition cost recovery rider increase and a \$1.5 million base rate increase. These lead to a difference of about \$17 million between the \$18.2 million base rate increase sought by TNMP and the staff's recommendation of \$1.5 million. Approximately \$14 million of the difference is made up of net operating income items while the remaining \$3 million results from a lower recommended return on equity. The biggest NOI items are a reduction in D&A expense (\$5 million) and a flow through of tax benefits to ratepayers (\$5 million).

The company announced a settlement with all parties to the case had been filed with the PUCT on June 22, 2009. The agreement would allow a \$6.8 million increase in base rates and an additional revenue increase of \$5.9 million to cover Hurricane Ike restoration

and increased financing costs. This settlement for a \$12.7 million total revenue increase was black box in nature. Hearings were held the week of June 16 2009 and a PUCT decision is expected prior to early October

Pepco Holdings (POM)

POM's regulatory calendar on the state level in 2008 was focused towards the beginning of the calendar year, while the company remained active with FERC through the latter part of the year with regards to the Mid-Atlantic Power Pathway (MAPP) transmission line. POM did receive some good news on 10/31/2008 when FERC approved the 150 bp adder, bringing POM's allowed ROE on the project to 12.8%. The lack of activity in 2008 on the state regulatory front brings on a busy 2009 for POM, with all subsidiaries filing rate cases in at least one jurisdiction, and some additional regulatory matters (addressed below in greater detail) with regards to pension and other benefit expense trackers, stimulus funding for efficiency and smart meters, and low cost financing options from the DOE for MAPP.

Pepco

POM's Pepco subsidiary recently filed (5/22/2009) their first rate case of the year, and probably POM's most significant of 2009, in Washington D.C. The company is currently asking for a \$51.7 million revenue increase, premised upon an 11.5% ROE and an equity-to-total-cap ratio of 53.8%. Washington, D.C. can at best be described as an average jurisdiction from an investor's standpoint, and as a result, we have, in our view, tempered expectations for how much of the company's current ask will actually be allowed by the PSC. This is further reinforced after looking at Pepco's most recently decided rate case in D.C. The final order included a revenue increase of \$28.3 million, premised upon a 10.0% ROE and an equity to total capitalization ratio of 46.6% (for rates effective 2/20/2008), after the company originally requested a revenue increase of \$50.5 million with an 11.0% ROE and 46.6% equity-total cap ratio.

Rounding out Pepco's near-term regulatory schedule is an expected filing in Maryland during 1Q10. We have baked into our estimates \$44 million in rate relief for all of Pepco (the company is 53% in D.C and 47% MD by rate base), reflecting a fairly dour, however realistic, result in both cases. The asking amount in MD's rate case is not expected to be of nearly the same magnitude as D.C.'s filing, as the company manages to earn much closer to their allowed ROE. Furthermore, Pepco's rate case history in Maryland, as exhibited by the gross discrepancies between the company's initial requests and the commission's final orders, can be described as negatively leaning at best.

DPL

On 5/6/2009 DPL filed a rate case in Maryland, requesting a revenue increase of \$14.15 million, premised upon an 11.25% ROE and a 49.9% equity to total cap structure. While Maryland is not, in our view, a jurisdiction that is constructive for utilities, DPL has historically had fairly good regulatory relationships. In DPL's last MD rate case, the company's final revised request was for a revenue increase of \$15.8 million, with a 10.75% ROE, and a 48.6% equity to total cap ratio. The MPSC's final order was for a

revenue increase of \$14.9 million with a 10.0% ROE and a 48.6% equity to total cap ratio.

DPL is also expected to file an electric rate case in Delaware during 3Q09 followed by a gas rate case filing in Delaware during 2Q10. DPL's Delaware jurisdiction (58% of electric rate base) is, in our view, average to slightly better than average, and the company's better (relative) performance there (adjusted earned ROE of 8.20%) makes the upcoming case there somewhat less important relative to the current case in Maryland. Baked into our estimates is total relief for DPL's electric operations in Maryland and Delaware of \$18 million. We believe that our rate case outcome assumption is reasonable, and may prove to be optimistic if Maryland's case doesn't come to fruition as constructively as the most recently decided case did.

ACE

During the third quarter of 2009, POM's ACE subsidiary will be filing a rate case in New Jersey. Baked into our estimates for ACE is rate relief of \$16 million, an amount that may prove to be conservative but that we are comfortable with especially when considering NJ's historically uncertain regulatory track record.

Pension Deferral Filings

On May 1, 2009 POM filed in all of their jurisdictions a request to defer, in aggregate, \$35 million in pension expense for 2009. The amount deferred would then be incorporated into the next rate case filing for each utility, respectively. In addition, POM is making a push to establish a three year moving average of pension, other employee benefit, and bad debt expense that would help to mitigate the cost increases for POM by allowing a surcharge and would dampen the rate shock consumers experience when the expenses would otherwise roll into rates after cases.

Potential Benefits from the Stimulus Package and DOE Initiatives

POM's "Blueprint for the Future" program is a good candidate for the government stimulus funds that have been earmarked for smart meters, efficiency, and conservation programs in general. Although the competition for the government funds is most likely going to be quite stiff (preliminary indications are that only six to eight projects nationwide may be in the first round to receive funding), we believe that it is definitely a possibility that POM will at least partially secure funds from the government's program. In addition, we think that POM's MAPP transmission line is a strong candidate for the DOE's loan guarantee program. If POM is successful in their application, their financing cost for the project would drop substantially (could be as much as 300-400 bp of incremental benefit in terms of reduced borrowing costs on POM's request for \$684 million in MAPP financing). It is beginning to appear increasingly likely that POM will benefit from the DOE's program (on May 27 POM was told by the DOE that their application was selected for a due diligence review) with a final decision expected tentatively during 3Q09.

Portland General Electric (POR)

POR received a final order on January 22, 2009 in its most recent GRC. The corresponding rate base associated with the order was \$2.278 billion. POR's authorized ROE under the order was 10.1%, with an equity structure of 50%. The order further authorized POR's proposed decoupling mechanism (described below); a condition of this mechanism was a reduction in the company's allowed ROE from 10.1% originally authorized to 10.0%. POR's general rate cases utilize a forward-looking test year. The company calculates allowance for funds used during construction (AFUDC) on construction work in progress, and when capital projects are placed into service, both capital investment and AFUDC are included in rate base. Pending or planned cases include:

- UE-204, which is a request for recovery of costs associated with Selective Water Withdrawal Project, with an estimated cost of \$80 million (POR's share). An implementation date under existing rate parameters is pending. A prehearing conference will be held following the conclusion of POR's root cause analysis of certain operational complications
- Annual Power Cost Update Tariff, for which an initial filing was made in April 2009 and will be made once again in April 2010, to adjust rates to reflect updated forecasts of net variable power costs. This is expected to be implemented on January 1 of the year following the filing. Under the Annual Power Cost Update Tariff, customer prices are adjusted annually to reflect the latest forecast of net variable power costs for the following year. As required, the company's initial forecast of 2010 power costs was submitted to the Oregon PUC (OPUC) on April 1, 2009. Such forecast will be updated during the year and will be finalized in November. Based upon the final forecast, new prices, as approved by the OPUC, will become effective January 1, 2010.
- Renewable Adjustment Clause Filing, for Biglow Canyon II project made in April 2009 for deferral until the project would be included in rates on January 1, 2010. The company anticipates a similar filing for Biglow Canyon Phase III in 2010.

Decoupling Adopted

A decoupling mechanism was approved in POR's recent rate case filing (UE-197). The decoupling mechanism referred to as the "Sales Normalization Adjustment" (SNA) and the Lost Revenue Recovery (LRR). The SNA applies to residential customers is simple balancing account and rate adjustment process that would greatly diminish the disincentives of supporting and encouraging innovative and effective programs to improve customer energy efficiency. The disincentives are manifest through reduced energy usage that in turn lowers POR's revenues, particularly revenues to cover the fixed costs of POR's operations. In addition to the SNA for residential customers, the Commission approved the LRR decoupling mechanism applied to large non-residential customers the loads less than 1mW.

Advanced Metering

POR will deploy 850,000 “smart meters” to residential and commercial customers. The company deployed approximately 16,000 meters in the systems acceptance testing phase of the project. The systems acceptance testing phase has been completed and full deployment of the remaining meters began in April 2009. The project is expected to be completed in 2010 with an estimated cost of \$130 million–\$135 million.

PPL Corp (PPL)

PPL Corp. is a vertically integrated utility in Pennsylvania which operates an unregulated generation subsidiary, PPL Supply, a regulated T&D utility, PA Electric Delivery, and an International Delivery segment which owns and operates T&D assets in the United Kingdom.

PPL Supply and Rate Caps in PA

PPL Supply currently operates under rate caps for their provider of last resort (POLR) load that were put in place in PA when the generation industry was deregulated. These rate caps are set to expire on 1/1/10. The other companies still operating under rate caps in PA (EXC, FE, AYE) remain capped until 1/1/11. PPL Supply filed with the PA Public Utility Commission (PA PUC) in 2007 to procure power for 2010 under six auctions to be held twice a year. This was done to allow for a “dollar cost average” type approach to power procurement and not leave the entire load vulnerable to price spikes in either direction on any particular day. Power has been procured under the approved auction process in five auctions so far, with pricing as indicated in Figure 39.

Figure 39: PPL Auctions

PPL Auction Results & Expectations	5th Auction on 3/31/09	4th Auction on 9/29/08	3rd Auction on 3/24/08	2nd Auction on 10/1/07	1st Auction on 7/23/07
<u>Off-Peak</u>					
PJM West Hub 7x8	\$ 43.00	\$ 54.63	\$ 48.39	\$ 42.23	\$ 37.71
PJM West Hub 2x16	\$ 43.00	\$ 68.24	\$ 67.44	\$ 64.34	\$ 68.79
<u>On-Peak</u>					
PJM West Hub 5x16	\$ 58.00	\$ 84.41	\$ 83.72	\$ 78.86	\$ 77.43
PJM West Hub ATC	\$ 50.14	\$ 71.40	\$ 68.84	\$ 63.88	\$ 62.54
Total Gap to ATC (1)	\$ 36.60	\$ 40.82	\$ 39.96	\$ 41.12	\$ 35.46
Expected/Actual Auction Result	\$ 86.74	\$ 112.23	\$ 108.80	\$ 105.00	\$ 98.00
Notes:					
(1) Gap includes capacity payments, line losses, ancillary services, etc					
Multiple of ATC price	1.73x	1.57x	1.58x	1.64x	1.57x

Source: Bloomberg, Barclays Capital Estimates

The issue of rate shock came to the fore in PA in 2008 as the auction prices for power were significantly above the current capped POLR rates. To mitigate rate shock to end use customers PPL proposed a rate mitigation plan with the PA PUC under which cash collections from customers would be delayed, and the difference between actual cash rates

charged to customers and revenue booked at market rates would be hung on the balance sheet. This would allow PPL to go to market but would slowly raise rates for customers over a three year period. In other words, rather than, for example, say a 24% increase in 2010 the customers would see an 8% increase per year for the next three years.

Political pressure from the Legislature increased in 2008 with attempts to extend rate caps as well as a compromise proposal that would have sanctioned the mitigation plan concept into law. Late in the 2008 session, the PA Legislature passed HB 2200 from which the extension of rate caps was removed. The bill passed 47-3 in the Senate and 157-32 in the House, and called for "least-cost" and "competitive-procurement" requirements which would allow for RFPs for power and long term contracts for procurement instead of or in addition to auction processes. The bill also included new requirements for PA PUC review of long term power contracts, demand side management targets of 2.5% around the clock, and 4.5% on-peak consumption reduction in five years time, and for smart meters to be depreciated over 15 years.

The debate over rate cap expiration, as expected, has begun anew in the 2009 legislative session. House Speaker McCall (D) has introduced House Bill 20 which would write into law rate mitigation plans similar in nature to the one PPL has filed and that has received PA PUC approval. Also, Bud George (D) has introduced a rate cap extension bill similar in nature to the one he introduced in the 2008 session which did not pass. It is likely that the budget process dominates legislative activity through the summer and rate cap or rate mitigation issues will not come to the fore until September and October of this year.

PA Electric Delivery

We anticipate that PA Electric Delivery will file a rate case with the PA PUC in the spring of 2010 for rates to be effective 1/1/11. The regulatory process in PA would be expected to take approximately nine months to complete. The company's last rate case was adjudicated in 2007 with a commission decision on 12/6, which allowed a \$55 million increase in revenues, or +1.7%. Internal metrics of the rate case were not specified. The company had requested an \$83.6 million revenue increase premised upon a rate base of about \$2.0 billion, a 43.13% equity ratio and a return on equity of 11.5%.

International Delivery

In the U.K. regulatory and rate setting process works differently than it does in the United States. Under the U.K. rate structure all utility companies go in for a rate review at the same time under which rates are set for the next five year period, otherwise known as a Distribution Price Control Review (DPCR). The U.K. regulator will perform a regression analysis to find the theoretical maximum efficient company. The regulator will then determine the returns and overall revenue requirement that this theoretical company would earn. Then each company is placed where they belong along the regression according to various measures of efficiency and their revenue requirements and returns are thus determined. The process allows for the company to set a capital and O&M budget for the next five years. The companies also have an opportunity to earn bonuses above and

beyond their revenue requirements for the highest customer service ranking (which PPL has been awarded for some time) and for the lowest cost of service, although this mechanism does not make adjustments for the natural cost differentials between a rural and an urban system. Initial proposals under the DCPR currently under way are expected in July 2009.

Progress Energy (PGN)

Progress Energy Florida (PEF)

On March 20, 2009, PEF filed with the Florida Public Service Commission (FL PSC) for a \$500 million rate increase, premised upon 50.5% equity and a 12.54% ROE. The new rates would be effective for January 1, 2010. PEF is asking for a 2010 test year in the process. As part of this rate request, PEF asked for \$13 million in interim rates. PEF is also filing for \$63 million of rate relief associated with the repowering of the Bartow plant, which is scheduled to come on-line in June 2009. The FL PSC approved both the interim and Bartow requests in full, subject to refund, on May 19. The \$76 million in higher rates were effective as of July 1. On April 9, PEF received approval for a reduction in fuel expenses of \$206 million. Taking this into account, the net increase of the fuel reduction and rate increase request would result in, at most, a \$294 million increase to customers by January 2010. The FL PSC is expected to rule in late December on the base rate increase. As we've noted previously, recent constructive decisions in Florida, as well as the accompanying reduction in fuel costs, suggest to us that a positive outcome is probable at PEF.

In May, PEF announced it would be postponing by 20 months the construction schedule of its proposed Levy nuclear site – suggesting an on-line date for the project of 2020 or later. The NRC has provided a limited work authorization for the green field site, and PEF has recently concluded that the authorization does not contemplate some of the more advanced site prep work they had planned until the NRC gets more comfortable around the geology and seismology of the nuclear island which is located in a wetlands environment. We expect full authorization and the COL will be issued at some point – likely in late 2011 or early 2012 – but the delay should lower capex for 2009 and 2010 by about \$100 million and \$350-400 million, respectively.

On the subject of cost recovery for expenses related to the Levy build, PEF updated its filings before the Florida PSC on May 1. Through 2009, PEF estimates that it will be about \$300 million under-recovered in Florida. Under existing statute, PEF would be able to recover that \$300 million, plus 2010 spending adjustments, that would result in a customer increase of about \$446 million. Most of this amount would be a pass-through of costs and capital, and likely result in about \$32 million of higher earnings (for both Levy and the CR3 uprate). In PEF's May 1 filing, it proposed to defer the \$300 million under-recovery over five years – softening the 2010 rate increase to customers – if allowed to earn carrying costs on the deferred balance. The resulting change would reduce 2010 customer impact by about \$210 million, but would actually increase PEF's earnings by about \$29 million pre-tax (in addition to the \$32 million cited above) to reflect a return on carrying charges. This could add \$0.06–\$0.07 versus current projections, and we don't

believe this is currently included in consensus estimates. Hearings are expected in the matter from September 8–11, with a FL PSC vote likely around October 16. New rates would be effective in January 2010.

Progress Energy Carolinas (PEC)

In South Carolina, PEC filed to reduce fuel costs by \$13 million on May 7. A settlement was approved by the South Carolina Public Service Commission (SCPSC) in early June, with rates effective for July 1. Also in early May, the SCPSC approved a settlement regarding demand side management (DSM) and conservation that would allow PEC to recover those investments through an annual rider.

In North Carolina, the legislature allows for utilities to recover DSM expenses as part of its 2007 energy legislation. The North Carolina Utilities Commission (NCUC) has approved a 2008 request by PEC to recover DSM and renewable energy portfolio standards costs through clause mechanisms. PEC filed to reduce fuel costs by a small amount on June 4, 2009, and also made small filings to adjust efficiency and renewable costs. Hearings are slated for September, with orders expected in October. The adjustments would take effect on December 1, 2009.

Longer term, PEC has made filings to support its goal of improving its distribution grid via a \$260 million investment over five years. PEC sees these investments as a precursor to eventual smart grid upgrades, and as a part of its DSM work. A decision from the NCUC could be forthcoming with respect to both the details of the plan and its recovery mechanisms at any point.

Public Service Enterprise Group (PEG)

Public Service Electric & Gas (PSE&G)

PSE&G is in the middle of several rate filings and a fair amount of regulatory activity, as the economic situation in New Jersey has caused Governor Corzine to urge utilities to increase near-term spending on items such as energy efficiency and conservation in the interest of adding jobs to stem the recession's impact. To that end, PSE&G has filed for \$1.7 billion in infrastructure, conservation, and solar spending in the early part of 2009. \$698 million of infrastructure spending has already been approved by the New Jersey Board of Public Utilities (NJ BPU), which granted a 48% equity structure and 10% ROE – shy of the 51% equity and 10.5% ROE requests, but the company was also given a monthly true-up on actual spending to eliminate cash lag. The remaining \$963 billion is comprised of \$773 million of various solar initiatives, and \$190 million of conservation spending. Both requests are expected to be reviewed by the BPU over the summer. We expect similar treatment to that received for the infrastructure projects.

PSE&G also filed an electric and gas rate case in New Jersey on May 29, asking for a gross increase of \$230.6 million. This amount would be offset by \$97 million in reductions associated with lower gas commodity costs, resulting in a net requested increase of about \$133.6 million. The case is based on \$6.2 billion of rate base (\$3.8 billion

electric; \$2.4 billion gas), a 51.2% equity structure, and 11.5% ROE. It uses a 2009 test year, implying a part-historical / part-forward looking test year in the case. In addition, PSE&G is asking for a tracker mechanism on capex spending, which would further reduce regulatory lag. The filing should receive a ruling from the BPU within the next nine to 12 months.

Sempra (SRE)

SRE has the benefit of a very secure regulatory future in both the near and medium term. With the approval of a multi-year settlement on August 1, 2008, SRE's regulated subsidiaries (gas distributor Southern California Gas, SoCalGas) and gas and electric utility San Diego Gas and Electric (SDG&E) have annual revenue increases of about \$95 million locked up through 2011, keeping both utilities out of extensive rate case proceedings until 2012 is addressed. The more minor regulatory issue that SRE will be addressing with the CPUC in the coming months is SoCalGas's cost of capital tracking mechanism that is currently partially tied to 30 year treasury yields. SRE believes that due to government intervention in the treasury market, the artificially low yields are not adequately capturing the cost of capital for the utility. A final decision for SoCalGas is expected during 3Q09 and we believe that the commission is likely to allow the change, due in a large part to the fact that every other California utility has a cost of capital tracker tied to a utility bond index rather than a treasury bond index.

Efficiency, Conservation, and Renewables

Beyond traditional rate cases, SRE also had a successful 2008 in terms of efficiency, conservation, renewable related programs. With the rollout of SDG&E's \$500 million smart meter program already in process, additional smart meter installations planned for SoCalGas (final approval expected in 4Q09 with installations expected to begin in 2011), and final approval of the Sunrise Powerlink transmission line already in hand, SRE is well positioned to benefit from policies aimed at pushing a "green" agenda.

Southern Co. (SO)

Southern Company operates four regulated utility subsidiaries, Georgia Power, Alabama Power, Mississippi Power, and Gulf Power, located in GA, AL, MS, and FL, respectively. They also operate an unregulated IPP subsidiary, Southern Power, which acquires or builds generating assets and signs them to long-term contracts, a model which minimizes risk. The only upcoming regulatory item of significance for Southern is the upcoming June 2010 filing of a GRC at Georgia Power, and the regular annual processes in Mississippi and Alabama. The company is not expected to file a rate case in Florida at this time.

A summary of regulations by subsidiary is provided in Figure 40.

Figure 40: Southern Co. Regulations by Subsidiary

Base Rates	Alabama	Georgia	Gulf	Mississippi
Alternative Ratemaking	Rate RSE			PEP-4
Traditional Regulation		ROE Band	ROE Band	
Regulatory Clauses				
Fuel	Y	y	y	y
Purchased Power Energy	Y	y	y	y
Purchased Power Capacity	Y		y	y
Environmental	Y	y	y	y
Energy Conservation			y	
		Integrated	Need	
New Plant Certification	Y	Resource Plan	Determination	Certification
Storms	Y		Process	Process
			y	y
CWIP in Rates		New Nuclear	New Nuclear	New Baseload
Considerations				
Test Year Forward Looking	Y	y	y	y
				For
Rate Base Avg. Original Cost	Y	y	y	Environmental
				Capital
Valuation End of Period				Rate Base for
				PEP

Source: Company Slide Presentation

Below, we detail the regulation for each of SO's subsidiaries.

Georgia Power

Georgia Power is operating in accordance with a three-year accounting order that was settled and approved by the GA PSC on 12/18/2007. The settlement called for a base revenue increase of \$222 million for environmental spending recovery and a base rate increase of \$99.7 million. The company had originally requested \$406.7 million in 2008, with an alternative plan with incremental increases of \$191 million in 2009, and \$45 million in 2010. The ROE dead band range is the same as current at 10.25%–12.25%. In addition, the settlement calls for a rider which would allow for annual true-ups/downs related to environmental spending. Greater than this range, there is a two-thirds to one-third sharing of profits between customers and shareholders, respectively.

The Georgia commission is composed of five full-time commissioners who are elected to six year staggered terms in statewide elections. The chairmanship is rotated annually according to legislative stipulations; the current chairman is Doug Everett. We view Georgia as a constructive regulatory environment, despite the elected nature of the commissioners. Lauren McDonald is back on the commission after a hiatus since 2002 replacing Angela Spier. Commissioner Robert (Bobby) Baker faces re-election in 2010.

Georgia Power is required by law to file a rate case no later than June 30 of next year. July and August will likely constitute the requesting, gathering, and submittal of various data requests. The staff should issue its recommendation in late August or early September, after

which hearings will be conducted in the September/October timeframe. Cases in Georgia are filed on a forecast forward test year basis. By law Georgia Power is required to file a one year rate case, and in addition to this will likely file a recommended three-year accounting order plan. Georgia Power has done filings at the commission this way since 1995. We anticipate that the filed equity ratio will be about 51% using actual; however, it is important to note that in Georgia all short-term debt is excluded from that calculation. The Commission can adjust both the equity ratio and the ROE in its final order, so those will be two points of discussion. Historically, however, most of the discussion and any adjustments have occurred to the ROE.

Fuel recovery in Georgia is not automatic but requires a filing and a hearing before the commission to review and approve the forecast costs and the recovery of any differential balance between what was previously forecast and what was actually collected. Georgia Power is allowed to institute a fuel hedging program, which operates under a sharing mechanism whereby any benefits are allocated 75% to ratepayers and 25% to shareholders.

Alabama Power

Alabama Power operates under a rate stabilization plan. The current ROE range is 13%–14.5%, which has an adjusting point at 13.75%—i.e., if the ROE falls outside the specified range, rates will be reset to an ROE level of 13.75%. The RSE has been in effect for 20 years and will remain in effect until discontinued or modified as deemed necessary by the Alabama Public Service Commission. In fall 2004, the Alabama PSC also approved an environmental spending tracker, which allows for the forward-looking rate recovery of environmental spending. We do not currently anticipate a rate case to be filed for this subsidiary in the next 12–24 months.

The Commission saw the retirement of President Jim Sullivan, who chose not to seek re-election, in the past year. President Sullivan was the longest serving utility commissioner in the country, having served from 1983 to 2008. He was replaced by current President Lucy Baxley, a Democrat, and a former Lt. Governor and State Treasurer of Alabama. The company received \$168 million in a corrective rate package for 2009 and agreed not to seek base rate increases for environmental increases for 2009. Environmental increases were deferred not foregone.

Mississippi Power

Mississippi Power operates under PEP-4, which attaches performance enhancements around a benchmark ROE. On September 30, 2004, this benchmark ROE was set to 10.70%. Mississippi Power's last rate case concluded in 2002 and instituted a rate hike based on a 12.88% ROE. In the last PEP-4 review specifies an 11.6% ROE for Mississippi Power. We do not currently anticipate a traditional rate case to be filed for this subsidiary in the next 12–24 months. The company will make another PEP filing by the end of 2009.

Southern has proposed construction of a commercially sized IGCC plant and mine in Kemper County, Mississippi. The plant would be a mine mouth facility using locally mined lignite coal. The last cost estimate made public by Southern was \$1.2 billion for the IGCC plant and \$0.6 billion for the mine. Because the gasifier uses air blown based technology developed at SO's Wilsonville, Alabama test facility it works with low grade coal. A higher-cost oxygen blown IGCC technology would not work on low grade MS lignite coal. The plant would also capture CO₂ and use it in enhanced oil recovery to give the plant the same carbon dioxide profile as a natural gas CCGT plant. Merchant power suppliers in Mississippi opposed the plant before the MS PSC. The MS PSC has ruled that the plant will be vetted by the commission in two phases. The first phase will be a determination of need for which the proceeding will begin on June 26 and a final decision is scheduled for October 9. The second phase will consider what options for resources are available to meet the need determined by the first phase. The various parties can propose alternatives to the IGCC facility in the second phase, but the PSC has stated that they must be detailed proposals with testimony on technology, cost, and timing. The second phase will begin on October 15 and a final decision is currently scheduled for May 1, 2010. This may slightly push back Mississippi Power's previously announced construction timeline of 2010–2013, as the company had previously estimated having full permitting by the end of 2009.

Westar Energy (WR)

Kansas regulation has become substantially more constructive in recent years with the implementation of a number of new recovery mechanisms. These include a fuel recovery clause that adjusts quarterly and covers plant performance, annual adjustments (Energy Cost Recovery Rider) for environmental spending that flows directly into rates, pre-determination for large scale projects that reduces the uncertainty of recovery, and favorable treatment of extraordinary storm damage that helps to reduce the volatility of earnings. On June 2, WR filed with the Kansas Corporation Commission (KCC) a limited rate case seeking cost recovery for investments in the second phase of its Emporia Energy Center, and two Westa-owned wind farms in Kansas that were under construction, but not in operation at the conclusion of the company's 2008 GRC. This rate review was agreed to as part of the settlement reached by all parties in the 2008 general rate case, which the KCC approved in January 2009. WR is seeking a \$19.7 million or 1.5% increase in this abbreviated filing. The same rate case parameters of 10.4% ROE and 50.8% equity component of capital will apply. The process for this rate case will be similar to a traditional rate case filing at the KCC, with the application strictly limited to costs associated with the construction and operation of wind generation owned by Westar and the second phase of Emporia Energy Center. Assuming a 240-day statutory timeframe for the rate review, an order would be expected in late January 2010.

Rate Case components include:

- New investment of \$97.5 million, including \$70.8 million for wind and \$26.7 million for Emporia Energy Center Phase II;
- Return on Plant-in-Service of \$11.6 million;

- Depreciation of \$17.2 million, including wind depreciation of \$13.5 million and Emporia Energy Center Phase II of \$3.7 million;
- Operations and maintenance expense of \$8.1 million, including \$6.4 million of wind and \$1.7 million of Emporia Energy Center Phase II; and
- Production Tax Credits provide a \$17.2 million offset in this rate increase request.

Update to the Environmental Cost Recovery Rider Approved

On May 29, 2009 the KCC approved an update to WR's Environmental Cost Recovery Rider (ECRR) following an audit and recommendation from KCC Staff. The KCC approved the \$32.4 million ECRR to go into effect June 1, 2009. The ECRR is a tariff that permits WR to recover costs associated with federally mandated environmental improvements to its generation facilities in a timely manner.

Transmission Rate Recovery

A FERC formula rate adjustment is applied annually; the KCC has approved a Transmission Delivery Charge (TDC) tariff to allow a corresponding retail adjustment, which enables timely recovery of transmission system operating and capital costs.

Wisconsin Energy (WEC)

Wisconsin Energy's Wisconsin Electric Power Co. (WEPCO) and Wisconsin Gas (WG) initiated a general rate case proceeding for its retail customers with the Public Service Commission of Wisconsin (PSCW) on March 17, 2009 with new rates to be effective January 1, 2010. The filing includes a \$76.5 million or 2.8% electric increase and a \$22.1 million or 3.6% gas increase, plus \$2.7 million increase for steam at WEPCO, and a \$38.9 million or 4.6% increase at Wisconsin Gas. WEC is requesting to retain a 10.75% regulatory ROE on 53% equity on a rate base valued at \$3.512 billion at WEPCO Electric, \$412.95 million rate base at WEPCO gas operation (WE Gas) and \$51.5 million in WEPCO steam operations; and 48% equity component on a rate base of \$611.5 million at WEC's Wisconsin Gas subsidiary. In an adjusted proposal filed in early July, WEC is now seeking a \$126 million electric revenue increase, an additional \$50 million from its initial electric increase request, citing the deepening recession and correspondingly lower sales. As part of the filing WEC also has requested 1) a reduction in depreciation rates concurrent with the implementation of new base rates in this proceeding; 2) certain regulatory assets currently scheduled to be fully amortized over the next four years will, instead, be amortized over the next eight years; 3) WEPCO will be permitted to continue to record 100% AFUDC for capital expenditures on environmental control projects and renewable energy projects; and, 4) WEPCO will have the option of applying for a limited reopener of this case or for deferred accounting to address any increased costs or reduced sales that would result from the enactment of recommendations of the Governor's Global Warming Task Force. We expect a PSCW Staff recommendation by September 2009 and Commission decision in the fourth quarter.

WEC's Michigan utility, Edison Sault Electric Co., filed a General Rate Case on July 2, 2009. The company is proposing a \$40 million or 33% rate increase, phased in over three stages, in 2010. The majority of the additional expenses are due to the Oak Creek Generating Units. Unlike in Wisconsin, where these costs have been gradually included in rates since 2003, Michigan does not allow power plant construction costs to be recovered until units are operational. The first phase of the increase of approximately \$20 million is scheduled to start in January 2010 to coincide with Oak Creek Unit 1's commercial operation. That 16.8% increase would also cover a change to the Michigan business tax. If the Michigan Public Service Commission agrees with Edison Sault's plan, another increase would be implemented in August 2010, when Unit 2 comes on line, and a third increase of about 15% would be implemented after the PSC finishes its audit of the application. The case requests a 10.75% return on equity.

Xcel Energy (XEL)

XEL's regulatory framework continues to improve, as forward test years in Minnesota, Wisconsin, and North Dakota – along with a pending forward test year request in Colorado – as well as interim rates in the first three of those states, have the company well positioned to continue to enjoy reduced regulatory lag. Transmission, renewable, and environmental riders exist in most jurisdictions as well. Only Texas and New Mexico continue to be material challenges from a regulatory standpoint, and XEL is fortunate in that regard as well, since its Southwestern Public Service (SPS) subsidiary that operates in those states comprises only about 5% of XEL's earnings.

Northern States Power – Minnesota (NSP-MN)

In Minnesota, XEL filed a base rate increase request of \$156 million in November 2008. This was based on \$4.1 billion of electric rate base, a 52.5% equity structure, and an 11% ROE. An interim increase of \$132 million went into effect at the beginning of January 2009, with the difference between XEL's request and the interim amount being owed to the last allowed ROE of 10.54% and the 11% requested in this case. Minnesota Department of Commerce testimony has been supportive of a rate increase closer to \$73 million, based on a 10.88% ROE. A ruling is expected during 3Q09.

Not including fuel recoveries, riders pertaining to about \$60 million in 2009 recoveries related to the MERP, transmission, and renewable energy mechanisms are pending before the Minnesota Public Utilities Commission (MPUC) as well.

As a final matter, NSP-MN is proposing license extensions at its Monticello and Prairie Island nuclear plants, as well as uprates of 71 MW and 164 MW, respectively. These projects are estimated to cost \$1.1 billion, with construction coming from 2009–2015. The Monticello plant has received all of its approvals except NRC approval for the uprate, which is expected as early as later this year. The Prairie Island plants still require MPUC certificates of need for the additional dry cask storage and for the uprate, both of which are expected later this year, and NRC approvals for the license extension and the uprate, which are expected in 2010.

Northern States Power – Wisconsin (NSP-WI)

NSP-WI is awaiting a ruling on a request for \$30.4 million in higher rates based on \$644 million of rate base, a 53.12% equity structure, and a 10.75% ROE. This case assumes a 2010 test year, and a decision is expected in December 2009.

Public Service Company of Colorado (PSCo)

PSCo has been busy of late, with a rate case that just concluded, and a phase 2 case just beginning. The concluded phase allowed for a \$112.2 million rate increase, versus a \$159 million revised request. The request was premised upon \$4.1 billion of rate base, a 58.08% equity structure, and an 11% ROE. Although the final order from the Colorado Public Utilities Commission (CPUC) didn't specify whether the 2009 forward test year had been granted, the size of the rate increase suggests that the commission was amenable to the general concept of allowing 2009 investments to be considered in the result, and is constructive in light of the phase 2 process that is currently under way.

Phase 2 is asking for a \$180 million increase, based on \$4.4 billion of rate base, a 58% equity structure, and an 11.25% ROE. This case assumes a 2010 test year, and a decision is expected by year end.

Southwestern Public Service Company (SPS)

In New Mexico, SPS recently filed an uncontested settlement that would allow a \$14.2 million rate increase, effective July 1, 2009. This was premised upon \$321 million of rate base, with a 50% equity structure and a 12% ROE. The case used a June 30, 2008 historical test year, and the terms of the settlement would prohibit SPS from filing its next base rate case until December 1, 2010. The settlement is pending approval before the NMPRC.

A base rate case in Texas that awarded a \$57.4 million rate increase was approved by the PUCT on May 21. Like the settlement in the PSCo case, this was a black box settlement that did not specify return metrics. SPS in Texas would be prohibited from filing another base rate case until February 15, 2010.

Emerging Issues: Coal, Stimulus, Climate Change, DSM, & Decoupling

Coal

Coal fueled 48.5% of net generation in the United States in 2009 and is domestically supplied. While conservation efforts and renewable sources show promise to reduce peaks and supply intermittent baseload or peaking generation capacity, for high capacity factor baseload generation the two viable options remain nuclear and coal. Nuclear is in a nascent recovery, although the first plants are not expected to be on-line until the end of the next decade. Despite short-term opposition, in the long run, coal remains the United States' largest domestic supply of energy. With the return of economic growth, it is likely that coal plants will need to be built in the country in order for supply to meet growing demand.

In our view, however, coal plants, both existing and potential new build, will become relatively more expensive as a result of environmental regulations around mercury, coal ash ponds, SO_x, and NO_x, and greenhouse gases. The continued push toward more stringent environmental regulation will make coal plants incrementally more expensive to run and build, and it will also likely lead to a "run or shutter" analysis based upon economics for many small older coal plants in the United States. Retrofits for environmental controls on these plants would in some scenarios be too expensive to justify keeping them running. Some of these plants also have limited available land surrounding them on which to build any emission control equipment.

The fourth quartile coal plants in the United States on average were built in 1959, run at a capacity factor of 58%, and at a heat rate of 15,549. These plants have a non-fuel O&M rate of \$18.21/MWh, almost 3x the 3rd quartile cost of \$6.64/MWh. Most of these plants are located in the Mid-Atlantic, South, and Midwest. In our view these plants could all face retirement with the coming more stringent environmental policies. These plants approach 10% of the nation's capacity which must be replaced by other baseload resources.

Coal Ash

In December 2008, the Kingston Plant, owned and operated by the Tennessee Valley Authority (TVA) experienced a dike failure on its coal ash pond, which allowed five million cubic yards of water and coal fly ash to cover 300 acres, 292 of which were owned by TVA. Since the incident TVA has purchased seven of the eight remaining effected acres. The cause of the failure is not yet known but ash also flowed into the nearby Emory River. The Kingston facility continued to run after the breach, albeit at a low capacity factor and currently produced ash was being mixed with clean up ash to be removed together. TVA took a charge of \$525 million that reflected the low end of the estimated immediate clean-up costs of \$525 million to \$825 million. This range does not contemplate the costs of other needed site work, or long-term clean up issues.

More broadly the Kingston incident has led to a full review by the Environmental Protection Agency (EPA) and we anticipate that further rules and regulations will eventually be

developed around the disposal and storage of coal ash waste. On March 9, 2009 the EPA released measures intended to prevent similar coal ash releases to the Kingston incident. The EPA plans to survey coal plants nationwide to gather information on structural integrity, order repairs where necessary, and develop new regulations. They released a list with 44 sites they cited as having “high hazard potential” at the end of June. Importantly, this list does not indicate any structural or safety problems at these sites, but rather reflects the likelihood of loss of human life in the event of a failure. The EPA has stated that they intend to have new regulations out for public comment by the end of 2009.

North Carolina Clean Air Case

In a ruling against TVA in a suit brought by North Carolina the courts determined that TVA’s coal plants were a public nuisance and were blowing emissions east into that state. A federal court judge ruled in North Carolina’s favor on four of TVA’s plants and declined to order relief on the rest of TVA’s coal fleet. The four plants affected were Bull Run (one unit), John Sevier (four units), Kingston (nine units) all in Tennessee and Widows Creek (eight units) in Alabama. The total capacity of the impacted facilities was 4,505 MW while the non-impacted facilities constituted 9,964 MW. Of particular concern was the judge’s order to accelerate the timeline of already planned and in process construction of emission controls – completion of the Kingston scrubbers and SCRs by 12/31/10, scrubbers and SCRs installed at John Sevier by 12/31/11 and scrubbers and SCRs on all Widows Creek units by 12/31/13. It is worth noting that all the plants mentioned are in current compliance with clean air rules and that TVA has invested \$5.1 billion in emission reduction programs for their coal fleet from 1977 to 2008. The company estimates that a further \$3.0 billion to \$3.7 billion (\$256/kW) could be required to be spent for new clean air and mercury regulations beginning in 2011, without contemplation of carbon.

TVA is already performing some of the court order’s requirements, Bull Run and Kingston emission control programs are already within the court’s guidelines. The two existing scrubbers at Widows Creek are currently being modernized. The court order would essentially require TVA to accelerate the schedule for control equipment at John Sevier and the remaining units at Widows Creek. This would cost an estimated additional \$1 billion versus its current plans. Given that John Sevier is TVA’s easternmost coal plant it is in a critical position for reliability in eastern Tennessee. TVA has appealed the court ruling and has announced intentions to build an \$820 million natural gas plant in eastern TN in case the appeal fails and John Sevier faces potential shut down. There are concerns with shifting from coal to natural gas including more volatile fuel input costs and actual ability to obtain and secure necessary locational supplies.

The TVA lawsuit bears watching as if the company’s appeal is unsuccessful several more lawsuits by states and/or environmental groups against existing coal fired generation, even with regard to carbon emissions could come to the fore and put more baseload generating capacity at risk. The case is also instructive in that replacing fourth quartile coal plants with natural gas would potentially create localized supply constraints, increase the demand and price for natural gas as well as its volatility. This would in turn impact the price, volatility, and potentially the reliability of electricity. Over the longer term, with coming mercury and

carbon regulations similar situations to TVA's could play out on a national scale without the courts, as pure economic decisions begin to force contemplation of shut downs.

Stimulus Bill

The stimulus bill that was passed in February 2009 provides approximately \$39 billion for energy programs, primarily focused on efficiency, renewable generation, and electric transmission and distribution.

Of this, \$16.8 billion is earmarked for Department of Energy efficiency and renewable energy programs, including \$3.2 billion for energy efficiency and conservation block grants, \$5 billion for weatherization assistance, \$2 billion for advanced battery manufacturing for electric vehicles, and \$3.1 billion for state energy programs. The language surrounding the conditions for the State Energy Efficiency Grants program puts forth some potentially industry changing possibilities. The amendments declare that states receiving funds from the program must have their governor confirm that they have assurances from the state regulatory authorities that they will seek to implement policy that aligns utility financial incentives with more efficient customer use. If this is enforced as strictly and literally as possible, one could take it as indicating that commissions will need to move toward the decoupling of revenues from sales in order to receive the stimulus funds.

In addition, the bill includes \$4.5 billion of new funding for a range of electric delivery and energy reliability activities, \$3.4 billion in funding for fossil energy research including clean coal and industrial carbon capture, and finally, an additional \$6 billion for the DOE loan guarantee program that is available only for renewable energy, electric power transmission, and leading edge transportation biofuel projects. This caveat of the loan guarantee program effectively excludes clean coal and advanced nuclear projects from the \$6 billion in additional funding that is being made available. The additional money also carries the stipulation that construction must begin by September 30, 2011, and by also removing the language that previously made only "innovative" technologies eligible, established technologies like wind, solar, and electric transmission can also now benefit.

Specific to transmission, the stimulus bill also directs the DOE to expand its 2009 National Electric Transmission Congestion Study to include an analysis of the significant potential sources of renewable energy that are constrained in accessing markets by a lack of adequate transmission capacity; an analysis of the reasons for failure to develop adequate transmission capacity; recommendations for achieving adequate transmission capacity; and finally, to what extent state and federal level legal challenges are delaying transmission construction. The potential implications from the language included in the bill regard how it will affect the role of the FERC and its potentially increased siting powers.

Some of the most interesting components of the stimulus bill are on the tax incentive side and are major positives for companies with renewable exposure. Most significantly the bill:

Extended the in-service date for wind production tax credits (PTCs) to 12/31/2012, and for other renewable sources (closed-loop biomass, open-loop biomass, geothermal, small

irrigation, hydropower, landfill gas, waste-to-energy, and marine renewable facilities) to 12/31/2013;

Allowed the temporary election of Investment tax credits (ITCs) in lieu of PTCs for wind facilities placed in-service by 12/31/2012, and for other qualifying facilities placed in-service by 12/31/2013; and

Created the option for taxpayers to elect to receive a treasury grant equal to 30% (10% in some cases) of the cost of the renewable energy facility (assuming construction begins in 2009 or 2010) 60 days after the facility is placed in-service or after the grant application is filed.

While it still remains unclear in terms of when money from the stimulus program will begin to flow in any meaningful way, the consensus view is implementation is expected to begin in July, 2009.

Climate Change: The American Clean Energy and Security Act of 2009 (ACES)

Below we provide a summary by topic of the ACES legislation (a.k.a. the Waxman/Markey bill):

Renewable Portfolio Standard

The combined renewable and electric savings requirement starts at 6% in 2012 and rises to 20% in 2020. Up to one-quarter of the 20% requirement can be met with savings. Upon receiving and responding to a request from a state's governor, the Federal Energy Regulatory Commission can increase the energy efficiency portion so that renewables would be 12% and efficiency 8% to meet the 20% requirement. These regulations are for retail electric suppliers in excess of 4 MMWhrs.

The definition of renewable has been expanded and includes wind, solar, geothermal, hydro, biomass and qualified waste-to-energy. An electric supplier's requirement is reduced by existing hydro, new nuclear and CO₂ sequestered fossil-fueled plants. The penalty in lieu of compliance is a renewable energy credit at \$25/MW hr.

CO₂ Sequestration

If approved by entities representing two-thirds of fossil-based delivered electricity, the Carbon Storage Research Corporation would be formed. It would be funded by retail customers of fossil-based electricity at \$1 billion annually. It would be 4.3 cents per MW hr for coal, 3.2 cents per MW hr for oil, and 2.2 cents per MW hr for gas. Fifty percent of the funds shall be provided in the form of grants to projects with funds already committed to IGCC with sequestration. New plants from 2009–2013 must sequester 50% of CO₂ with 65% by 2020.

Efficiency

New building codes state 30%–50% higher energy efficiency targets from 2010–2016. Rebates up to \$7,500 toward purchases of new Energy Star-rated manufactured homes for low-income families in pre-1976 manufactured homes.

Global Warming Pollution Reduction

Economy-wide reduction goal is to reduce global warming pollution to 97% of 2005 levels by 2012, 83% by 2020, 58% by 2030, and 17% by 2050. Methane scores 25 x 1 CO2 credit. Offsets are 2 billion metric tons split evenly domestic and foreign. Emission levels can be increased by Administrator by up to 1.5 billion metric tons. Strategic reserve is 1% of total from 2012–2019, 2% for 2020–2029, and 3% for 2030–2050. Initial strategic reserve price floor is \$28/ton for 2012. Establishes an Offsets Integrity Advisory Board; otherwise, EPA establishes and runs the offsets program. Allowances are phased out for energy users from 2026–2030. Of the 38% for LDC rate reductions in 2012, 30% is electric, 7% is for gas, and 1% for other (government).

Figure 41: Emission Allocations & Allowances

Emission Allocations	Allocations		Fossil Fuel Companies in 2020		Emission Allowances (in millions)			
	2012	2020						
Fossil Fuel and Industry	8%	25%	Energy Intensive Industries	13%	2012	4,627	2030	3,533
LDC Rate Reductions	38%	36%	Coal Plant Operators	5%	2013	4,544	2035	2,908
LDC and State Efficiency	1%	4%	Coal CCS	5%	2014	5,099	2040	2,284
Clean Energy and Climate Programs	16%	10%	Oil Refineries	2%	2015	5,003	2045	1,660
International	7%	7%			2020	5,056	2046	1,535
Deficit Reduction	14%	2%	Clean Energy and Climate (at various times)		2025	4,294		
Consumer Rebates	16%	16%	Energy Efficiency/Renewable	9.5%				
			Clean Energy Research	1.5%				
			Clean Vehicles	3.0%				
			Domestic Fuels	2.0%				
			Workers	0.5%				
			Domestic Adaptation	0.9%				
			Wildlife	1.0%				

Source: American Clean Energy and Security Act of 2009; Barclays Capital estimates.

Electric Distribution Companies

Not later than 6/30/2011 and each calendar year through 2028, the Administrator would distribute 50% of allowances based on emissions of generation delivered at retail. For 2012–2013 the level would be based on 2006–2008 or any three consecutive years from 1999–2008. For 2014+, allocation would be based on the prior discussion or any three years from 2009–2012, or 2012 only if new generation is placed in service. The other 50% of distributions would be based on average annual retail electric sales from 2006–2008, unless the company selects any three consecutive years from 1999–2008. The distribution formula would be updated every three years. The allowances must go to ratepayer benefit, ratably among classes. The allowances cannot be used for a “rebate” and must track usage. The allowances cannot be authorized until the state regulatory body completes a proceeding authorizing their use.

Demand Side Management (DSM)

As talk around efficiency and conservation intensifies, we wanted to call attention to the fact that some states have made demand reduction a real point of emphasis and have pushed varying initiatives with a great deal of vigor. For instance, Michigan's implementation of a customer surcharge in order to pre-fund efficiency expenditures is among the more pro-active examples of a trend we expect to broaden to more and more states in the near future. Promoting these efforts are aggressive policy measures – at both the state and federal levels – that are meant to further encourage the implementation of efficiency technology, with a current example being the stimulus bill and the money being earmarked for states' "smart grid" and other efficiency programs.

When we looked at DTE's proposed conservation program (\$110 million in total, two-thirds of which is at Detroit Edison) we found that when thinking about and valuing DetEd's 1% in forecasted load reduction as an avoided generation plant (assuming a 60% capacity factor), we arrived at a value of \$800/kw. EIX's regulated subsidiary, Southern California Edison, however, had an implied value of \$1,700/kw (\$1.7 billion to reduce 1,000 MW of load) for its metering program.

We believe there are two logical takeaways from this: First, these early-stage programs will likely test the aggressiveness of the different states proposing and implementing this policy. For instance, SoCalEd currently works to achieve a 5% reduction in peak load, while its metering program would result in an additional 5% reduction. These are lofty targets, and stand in contrast to the more modest goals that have been set by many states. Second, in states like California, where generation is more constrained and aggressive renewable and reduction goals are in place, the cost of demand reduction should tend to be higher than it is in Michigan, for example. In other words, the avoided costs in California are higher than they are in Michigan, so the cost of the programs will naturally tend to be more expensive before running up against significant regulatory or ratepayer pushback.

We believe that reductions of about 1% annually – which have been the goals we've seen talked about in many jurisdictions – will be achievable for at least the first four to five years with targeted spending on very simple programs. These could involve such basic things as the weatherization of homes (\$5 billion of the stimulus bill already has been earmarked for this), the switching of light bulbs, and new design standards for buildings under construction. We think that reductions beyond the 5% level are going to require substantially greater investment to get to the next level of incremental benefit, with costs likely rising to match the level of aggressiveness. The direction from the federal government as we work through national energy policy this year will also codify the larger goals, and therefore give us a better sense for the acceptable levels of spending.

Application of Decoupling Mechanisms on the Rise

Although initially predominantly employed by the gas utility industry, revenue decoupling has gained momentum among U.S. electric utilities as well. Ten states have approved a revenue decoupling mechanism for electric utilities: California, Connecticut, Idaho,

Maryland, Massachusetts, Michigan, Minnesota, New York, Oregon, Vermont, and Wisconsin. Three are pending approval – Delaware, Hawaii and New Hampshire – according to the Institute for Electric Efficiency. Revenue decoupling currently is in use in six states: California, Connecticut, Idaho, Maryland, New York and Oregon.

One driver behind decoupling is passed and pending federal legislation – specifically the American Recovery and Reinvestment Act of 2009 – and the revised climate change bill drafted by Reps. Henry Waxman, D-Calif., and Edward Markey, D-Mass, which includes targets for energy efficiency resource standards, renewable energy standards, and a cap on carbon emissions. While the federal stimulus bill does not specifically require decoupling, incentives need to be in place for utilities to engage in additional energy efficiency initiatives. The stimulus bill provides roughly \$3 billion in state energy grants, and the Department of Energy has the authority to allocate these funds to the states, so long as the governor has been assured that the PUC in that state will implement regulatory policy that aligns utility financial incentives with the successful implementation of energy efficiency measures.

Decoupling has encountered some resistance from state legislatures and commissions to consumer advocates, likely because of the notion that the utility is not hurt by reduced consumption. Conversely, however, through decoupling, a utility will not see significant revenues from an increase in energy consumption. Generally accepted rate-setting practices create an inherent financial disincentive for utilities to participate in conservation programs, given that a successful energy usage reduction program would have a direct negative impact on utility revenues, and may require the utility to file a new general rate case in an attempt to recoup the related reduction in earnings. As environmental concerns have intensified, many states have adopted compulsory energy conservation standards and consequently, the need to mitigate the possible negative impacts of these programs has accelerated. Decoupling mechanisms are now being applied in some jurisdictions to encourage utilities to invest in mandated conservation programs without the associated potential negative effect on earnings. The decoupling mechanism enables the utility to defer fixed distribution costs that the utility may fail to recoup through its volumetric charges due to customers' participation in conservation programs. The utility is allowed to recover the deferrals associated with the unrecovered fixed costs through a surcharge over a period of time, generally with carrying charges on the deferred amounts.

An alternative to decoupling is a Straight Fixed Variable rate design, where a company's fixed costs are fully collected through the customer's fixed monthly charge. Consequently, the utility's fixed costs will always be recovered, regardless of the success of a company's conservation program, since the only volumetric charge is for the commodity. Therefore, by cutting back consumption, the customer would save only on the commodity portion of the monthly bill. Since these costs are also avoidable by the utility, earnings would not be negatively impacted. While the straight fixed variable rate design methodology provides a

direct cause-and-effect relationship between usage and customers bill levels, and is easier to administer than a decoupling mechanism, one noted drawback is that customer rate designs tend to include relatively low fixed charges, and shifting to a fully fixed rate would likely result in rate increases for the residential customers.

Figure 42: Barclays Capital Power and Utilities Coverage Universe

REGULATED COMP SHEET

Investment Opinion	Ticker	Company	Current Price 07/16/09	Indicated Annual Dividend	Expected Annual Dividend Growth	Current Yield	Earnings per Share			5 Year Est. EPS Growth	2008A Price/ Earnings	2009E Price/ Earnings	2010E Price/ Earnings
							2008A	2009E	2010E				
2-EW	LNT	Alliant Energy	\$26.28	\$1.50	10.0%	5.7%	\$2.54	\$2.25	\$2.55	2%	10.3x	11.7x	10.3x
1-OW	AEP	American Electric Power	\$29.95	\$1.56	4.0%	5.2%	\$3.24	\$2.91	\$3.03	2%	9.2x	10.3x	9.9x
1-OW	CMS	CMS Energy Corp	\$12.33	\$0.50	6.6%	4.1%	\$1.25	\$1.27	\$1.33	7%	9.9x	9.7x	9.3x
2-EW	ED	Consolidated Edison	\$37.69	\$2.36	1.0%	6.3%	\$3.00	\$3.19	\$3.30	2%	12.6x	11.8x	11.4x
1-OW	DPL	DPL Inc	\$23.65	\$1.14	5.0%	4.8%	\$2.12	\$2.23	\$2.65	15%	11.2x	10.6x	8.9x
2-EW	DTE	DTE Energy Co	\$32.73	\$2.12	0.7%	6.5%	\$2.90	\$2.96	\$3.22	0%	11.3x	11.1x	10.2x
1-OW	DUK	Duke Energy Corp	\$14.77	\$0.94	4.0%	6.4%	\$1.21	\$1.23	\$1.30	1%	12.2x	12.0x	11.4x
2-EW	GXP	Great Plains Energy	\$15.54	\$0.83	2.0%	5.3%	\$1.16	\$1.12	\$1.30	2%	13.4x	13.9x	12.0x
3-UW	HE	Hawaiian Electric Inds	\$17.55	\$1.24	0.0%	7.1%	\$1.49	\$1.35	\$1.38	-1%	11.8x	13.0x	12.7x
2-EW	ITC	ITC Holdings	\$43.58	\$1.22	4.0%	2.8%	\$2.19	\$2.27	\$2.56	17%	19.9x	19.2x	17.0x
2-EW	NI	NiSource Inc	\$12.22	\$0.92	0.0%	7.5%	\$1.27	\$1.05	\$1.04	-6%	9.6x	11.6x	11.8x
2-EW	NU	Northeast Utilities	\$22.21	\$0.95	5.6%	4.3%	\$1.87	\$1.79	\$2.10	13%	11.9x	12.4x	10.6x
2-EW	NST	NSTAR	\$30.93	\$1.50	7.0%	4.8%	\$2.22	\$2.40	\$2.58	5%	13.9x	12.9x	12.0x
1-OW	NVE	NV Energy	\$11.29	\$0.40	10.6%	3.5%	\$0.89	\$0.91	\$1.18	13%	12.7x	12.4x	9.6x
1-OW	PCG	PG&E Corp	\$37.73	\$1.68	7.9%	4.5%	\$2.95	\$3.18	\$3.46	8%	12.8x	11.9x	10.9x
2-EW	PGN	Progress Energy	\$37.75	\$2.48	1.0%	6.6%	\$2.98	\$2.96	\$3.13	-1%	12.7x	12.8x	12.1x
2-EW	PNM	PNM Resources	\$11.64	\$0.50	0.0%	4.3%	\$0.12	\$0.46	\$0.85	-12%	97.0x	25.3x	13.7x
RS	PNW	Pinnacle West Capital	\$30.88	\$2.10	0.0%	6.8%	\$2.29	\$2.30	\$2.74	-4%	13.5x	13.4x	11.3x
2-EW	POM	Pepco Holdings	\$13.86	\$1.08	2.0%	7.8%	\$1.23	\$1.10	\$1.43	-1%	7.2x	12.6x	9.7x
1-OW	POR	Portland General	\$20.08	\$1.02	7.5%	5.1%	\$1.71	\$1.80	\$1.87	13%	11.7x	11.2x	10.7x
2-EW	SO	Southern Co	\$31.80	\$1.75	5.0%	5.5%	\$2.37	\$2.30	\$2.45	3%	13.4x	13.8x	13.0x
2-EW	SRE	Sempra Energy	\$48.99	\$1.56	10.0%	3.2%	\$4.43	\$4.40	\$5.05	7%	11.1x	11.1x	9.7x
2-EW	TE	TECO Energy Inc	\$12.09	\$0.80	4.7%	6.6%	\$0.86	\$1.08	\$1.21	0%	14.1x	11.2x	10.0x
2-EW	WR	Westar Energy	\$19.08	\$1.20	2.0%	6.3%	\$1.27	\$1.65	\$1.75	3%	15.0x	11.6x	10.9x
1-OW	WEC	Wisconsin Energy Corp	\$41.44	\$1.35	3.0%	3.3%	\$3.03	\$3.15	\$3.90	10%	13.7x	13.2x	10.6x
2-EW	XEL	Xcel Energy	\$18.94	\$0.95	3.0%	5.0%	\$1.45	\$1.52	\$1.61	8%	13.1x	12.5x	11.8x
UTILITIES (26)					4.5%	5.4%				3.8%	12.8x	12.3x	11.3x
S&P 500 Index			940.7	\$28.48		3.0%	\$68.80	\$55.96	\$68.45	-6.0%	13.7x	16.8x	13.7x

Source: Company disclosures, FactSet, Barclays Capital estimates

POWER COMP SHEET

Rating	Ticker	Company	Current Price 07/16/09	Div. Yield	Asset Value	Potential Upside	Open EBITDA - '10		Current EBITDA - '10		Earnings per Share			P/E Multiples		Open P/E - '10		FCF Yield/EV	
							\$MM	EV Multiple	\$MM	EV Multiple	2008A	2009E	2010E	2009E	2010E	EPS	Multiple	2009E	2010E
1-OW	AES	AES Corporation	\$12.09	0.0%	\$13	4%	\$3,290	7.2x	\$3,332	7.1x	\$0.99	\$0.97	\$1.08	12.5x	11.2x	\$1.04	11.6x	-3.6%	1.2%
1-OW	AYE	Allegheny Energy	\$25.04	2.4%	\$40	60%	\$1,721	5.0x	\$1,338	6.4x	\$2.30	\$2.20	\$2.85	11.4x	8.8x	\$4.21	5.9x	1.2%	4.2%
2-EW	AEE	Ameren Corp.	\$24.61	6.3%	\$26	6%	\$2,008	8.3x	\$2,181	7.6x	\$2.89	\$2.83	\$2.70	8.7x	9.1x	\$2.21	11.1x	-2.9%	-3.3%
2-EW	CPN	Calpine Corp.	\$11.47	0.0%	\$8	-30%	\$1,188	10.3x	\$1,081	11.2x	(\$0.03)	\$0.42	(\$0.14)	27.5x	NM	\$0.00	NM	3.8%	2.7%
2-EW	CEG	Constellation Energy Corp	\$27.89	3.4%	\$43	54%	\$1,729	6.3x	\$1,720	6.4x	\$1.67	\$3.15	\$3.18	8.9x	8.8x	\$3.21	8.7x	1.5%	0.2%
1-OW	CVA	Covanta Holdings	\$17.66	0.0%	\$15	-15%	\$505	7.7x	\$530	7.3x	\$0.90	\$0.74	\$1.00	23.9x	17.7x	\$0.99	17.8x	2.4%	2.8%
2-EW	D	Dominion Resources Inc	\$33.17	4.8%	\$35	5%	\$4,654	7.8x	\$5,634	6.3x	\$3.16	\$3.08	\$3.19	10.8x	10.4x	\$2.60	12.8x	-0.3%	0.3%
2-EW	DYN	Dynegy Inc.	\$2.03	0.0%	\$4	113%	\$495	11.9x	\$796	7.5x	\$0.03	(\$0.06)	\$0.05	NM	NM	(\$0.18)	NM	0.7%	1.3%
2-EW	EIX	Edison International	\$31.45	3.9%	\$44	38%	\$3,654	6.3x	\$4,981	4.7x	\$3.84	\$2.88	\$3.22	10.9x	9.8x	\$1.92	16.4x	-4.8%	-3.6%
1-OW	ETR	Entergy Corp	\$75.64	4.0%	\$111	47%	\$3,293	6.8x	\$3,800	5.9x	\$6.51	\$6.76	\$7.28	11.2x	10.4x	\$5.58	13.6x	6.3%	6.7%
RS	EXC	Exelon	\$51.93	3.9%	N/A	N/A	\$5,571	7.7x	\$6,950	6.2x	\$4.20	\$4.02	\$4.28	12.9x	12.1x	\$3.64	14.3x	6.5%	6.9%
1-OW	FE	FirstEnergy Corp	\$40.80	5.4%	\$56	37%	\$3,765	6.9x	\$3,510	7.4x	\$4.57	\$3.75	\$3.47	10.9x	11.8x	\$3.93	10.4x	3.3%	3.4%
2-EW	FPL	FPL Group Inc	\$57.37	3.1%	\$69	21%	\$4,469	8.9x	\$4,793	8.4x	\$3.84	\$4.28	\$4.76	13.4x	12.1x	\$3.96	14.5x	2.7%	4.7%
2-EW	MIR	Mirant Corp	\$16.16	0.0%	\$9	-42%	\$481	7.8x	\$653	4.8x	\$2.60	\$2.56	\$1.53	6.3x	10.6x	\$0.12	NM	-4.5%	-1.3%
RS	NRG	NRG Energy	\$24.72	0.0%	N/A	N/A	\$1,798	6.9x	\$2,272	5.5x	\$2.52	\$2.92	\$2.41	8.5x	10.3x	\$1.10	22.5x	7.7%	6.6%
2-EW	ORA	Orrville Technologies	\$39.11	0.5%	\$33	-16%	\$168	12.7x	\$169	12.5x	\$1.12	\$1.20	\$1.46	32.6x	26.8x	\$1.54	25.4x	3.7%	6.0%
1-OW	PPL	PPL Corporation	\$32.80	4.2%	\$41	25%	\$3,098	6.8x	\$3,070	6.7x	\$2.02	\$1.73	\$3.52	19.0x	9.3x	\$3.57	9.2x	1.2%	2.6%
1-OW	PEG	Public Service Entrp Group	\$32.47	4.1%	\$41	26%	\$4,362	6.4x	\$4,176	6.6x	\$2.92	\$3.11	\$3.12	10.4x	10.4x	\$4.09	7.9x	3.3%	3.3%
2-EW	RRI	RRI Energy, Inc.	\$5.02	0.0%	\$11	119%	\$413	6.0x	\$507	4.9x	(\$0.13)	(\$0.66)	\$0.18	NM	27.9x	\$0.21	NM	-6.2%	12.0%
Group Average (19)				3.4%		18.6%		7.5x		6.8x				12.5x	10.8x		12.1x	2.5%	3.4%

Source: Barclays Capital estimates, FactSet.

Source: Barclays Capital Estimates, FactSet, Company Disclosures

Appendix

Figure 43: 2005 Rate Case Outcomes

Date	Company	State	Allowed ROE	Yield on 10-Year Treasury	Spread (bps)	Yield on Moodys Baa	Spread (bps)
01/06/05	South Carolina Electric & Gas	SC	10.70%	4.29%	641	6.13%	457
01/28/05	Aquila Networks-WPK	KS	10.50%	4.16%	634	5.91%	459
02/18/05	Puget Sound Energy	WA	10.30%	4.27%	603	5.89%	441
02/25/05	PacifiCorp	UT	10.50%	4.27%	623	5.89%	461
03/10/05	Empire District Electric	MO	11.00%	4.48%	652	5.99%	501
03/18/05	Dominion North Carolina Power	NC	--	--	--	--	--
03/24/05	Consolidated Edison of NY	NY	10.30%	4.60%	570	6.18%	412
03/31/05	Texas-New Mexico Power	TX	10.25%	4.50%	575	6.14%	411
	1st Quarter Averages		10.51%	4.37%	614	6.02%	449
04/04/05	Central Vermont Public Service	VT	10.00%	4.47%	553	6.12%	388
04/07/05	Arizona Public Service	AZ	10.25%	4.49%	576	6.14%	411
05/02/05	Public Service Co. of Oklahoma	OK	--	--	--	--	--
05/18/05	Entergy Louisiana	LA	10.25%	4.07%	618	5.99%	426
05/18/05	Wisconsin Electric Power	WI	--	--	--	--	--
05/25/05	Savannah Electric & Power	GA	10.75%	4.08%	667	5.99%	476
05/26/05	Atlantic City Electric	NJ	9.75%	4.08%	567	5.99%	376
05/26/05	Idaho Power	ID	--	--	--	--	--
06/01/05	Jersey Central Power & Light	NJ	9.75%	3.91%	584	5.82%	393
06/08/05	Public Service New Hampshire	NH	9.62%	3.95%	567	5.77%	385
	2nd Quarter Averages		10.05%	4.15%	590	5.97%	408
07/19/05	Wisconsin Power & Light	WI	11.50%	4.20%	730	5.98%	552
07/22/05	PacifiCorp	ID	--	--	--	--	--
08/05/05	Cap Rock Energy	TX	11.75%	4.40%	735	6.07%	568
08/15/05	AEP Texas Central	TX	10.13%	4.27%	586	5.98%	415
09/28/05	PacifiCorp	OR	10.00%	4.26%	574	6.08%	392
	3rd Quarter Averages		10.85%	4.28%	656	6.03%	482
12/09/05	Empire District Electric	KS	--	--	--	--	--
12/12/05	Madison Gas & Electric	WI	11.00%	4.56%	644	6.42%	458
12/13/05	OGE Electric Service	OK	10.75%	4.54%	621	6.42%	433
12/16/05	Pacific Gas & Electric	CA	11.35%	4.45%	690	6.30%	505
12/16/05	San Diego Gas & Electric	CA	10.70%	4.45%	625	6.30%	440
12/16/05	Southern California Edison	CA	11.60%	4.45%	715	6.30%	530
12/21/05	Cincinnati Gas & Electric	OH	10.29%	4.49%	580	6.33%	396
12/21/05	Avista	WA	10.40%	4.49%	591	6.33%	407
12/22/05	Consumers Energy	MI	11.15%	4.44%	671	6.27%	488
12/22/05	Wisconsin Public Service	WI	11.00%	4.44%	656	6.27%	473
12/28/05	Westar Energy North	KS	10.00%	4.38%	562	6.20%	380
12/28/05	Kansas Gas & Electric	KS	10.00%	4.38%	562	6.20%	380
12/28/05	Dayton Power & Light	OH	--	--	--	--	--
12/30/05	NSTAR Electric	MA	--	--	--	--	--
	4th Quarter Averages		10.75%	4.46%	629	6.30%	445
	2005 Average		10.54%	4.32%	622	6.08%	446

Source: SNL Financial, Federal Reserve

Figure 44: 2006 Rate Case Outcomes

Date	Company	State	Allowed ROE	Yield on 10-Year Treasury	Spread (bps)	Yield on Moodys Baa	Spread (bps)
01/05/06	Northern States Power	WI	11.00%	4.36%	664	6.20%	480
01/25/06	Wisconsin Electric Power	WI	--	--	--	--	--
01/27/06	United Illuminating	CT	9.75%	4.52%	523	6.30%	345
02/23/06	Aquila Networks-MPS	MO	--	--	--	--	--
02/23/06	Aquila Networks-L&P	MO	--	--	--	--	--
03/03/06	Interstate Power & Light	MN	10.39%	4.68%	571	6.35%	404
03/14/06	Kentucky Power	KY	--	--	--	--	--
03/24/06	PacifiCorp	WY	--	--	--	--	--
03/29/06	Entergy Gulf States	LA	--	--	--	--	--
1st Quarter Averages			10.38%	4.52%	586	6.28%	410
04/17/06	PacifiCorp	WA	10.20%	5.01%	519	6.71%	349
04/18/06	MidAmerican Energy	IA	11.90%	4.99%	691	6.69%	521
04/26/06	Sierra Pacific Power	NV	10.60%	5.12%	548	6.76%	384
05/12/06	Idaho Power	ID	--	--	--	--	--
05/17/06	Southern California Edison ⁽¹⁾	CA	11.60%	5.16%	644	6.82%	478
06/06/06	Delmarva Power & Light	DE	10.00%	5.01%	499	6.66%	334
06/27/06	Upper Peninsula Power	MI	10.75%	5.21%	554	6.91%	384
2nd Quarter Averages			10.84%	5.08%	576	6.76%	408
07/06/06	Maine Public Service	ME	10.20%	5.19%	501	6.85%	335
07/24/06	Central Hudson Gas & Electric	NY	9.60%	5.05%	455	6.74%	286
07/26/06	Appalachian Power	WV	10.50%	5.04%	546	6.72%	378
07/28/06	Commonwealth Edison	IL	10.05%	5.00%	505	6.67%	338
08/23/06	New York State Electric & Gas	NY	9.55%	4.82%	473	6.54%	301
08/31/06	Detroit Edison	MI	11.00%	4.74%	626	6.47%	453
09/01/06	Northern States Power	MN	10.54%	4.73%	581	6.46%	408
09/05/06	CenterPoint Energy Houston Elec.	TX	--	--	--	--	--
09/14/06	PacifiCorp	OR	10.00%	4.79%	521	6.49%	351
3rd Quarter Averages			10.18%	4.92%	526	6.62%	356
10/06/06	Unitil Energy Systems	NH	9.67%	4.70%	497	6.43%	324
10/27/06	Entergy New Orleans	LA	--	--	--	--	--
11/21/06	Delmarva Power & Light	DE	--	--	--	--	--
11/21/06	Central Illinois Light	IL	10.12%	4.58%	554	6.18%	394
11/21/06	Central Illinois Public Service	IL	10.08%	4.58%	550	6.18%	390
11/21/06	Illinois Power	IL	10.08%	4.58%	550	6.18%	390
12/01/06	Duquesne Light	PA	--	--	--	--	--
12/01/06	PacifiCorp	UT	10.25%	4.43%	582	6.08%	417
12/01/06	Public Service of Colorado	CO	10.50%	4.43%	607	6.08%	442
12/04/06	Kansas City Power & Light	KS	--	--	--	--	--
12/07/06	Central Vermont Public Service	VT	10.75%	4.49%	626	6.13%	462
12/14/06	Western Massachusetts Electric	MA	--	--	--	--	--
12/18/06	PacifiCorp	ID	--	--	--	--	--
12/21/06	Duke Energy Kentucky	KY	--	--	--	--	--
12/21/06	Empire District Electric	MO	10.90%	4.55%	635	6.23%	467
12/21/06	Kansas City Power & Light	MO	11.25%	4.55%	670	6.23%	502
12/22/06	Green Mountain Power	VT	10.25%	4.63%	562	6.30%	395
12/28/06	Black Hills Power	SD	--	4.70%	--	--	--
4th Quarter Averages			10.39%	4.57%	582	6.20%	418
2006 Average			10.45%	4.77%	567	6.47%	398

(1) ROE was determined in previously decided cost of capital decision.

Source: SNL Financial, Federal Reserve

Figure 45: 2007 Rate Case Outcomes

Date	Company	State	Allowed ROE	10-Year Treas. Yield	Spread (bps)	Moodys Baa Yield	Spread (bps)
01/05/07	Oklahoma Gas And Electric	AR	10.00%	4.65%	535	6.25%	375
01/11/07	Wisconsin Power & Light Co.	WI	10.80%	4.74%	606	6.33%	447
01/11/07	Pennsylvania Electric Co.	PA	10.10%	4.74%	536	6.33%	377
01/11/07	Metropolitan Edison Co.	PA	10.10%	4.74%	536	6.33%	377
01/12/07	Portland General Electric Co.	OR	10.10%	4.77%	533	6.36%	374
02/08/07	PPL Gas Utilities	PA	10.40%	4.73%	567	6.28%	412
03/15/07	Pacific Gas and Electric Co.	CA	11.35%	4.54%	681	6.24%	511
03/20/07	Delmarva Power & Light Co.	DE	10.25%	4.56%	569	6.27%	398
03/22/07	Rockland Electric Company	NJ	9.75%	4.60%	515	6.35%	340
03/22/07	Southern Union Co.	MO	10.50%	4.60%	590	6.35%	415
	1st Quarter Averages		10.35%	4.66%	569	6.31%	404
05/15/07	Appalachian Power	VA	10.00%	4.71%	529	6.36%	364
05/17/07	Aquila (MPS)	MO	10.25%	4.76%	549	6.40%	385
05/17/07	Aquila (L&P)	MO	10.25%	4.76%	549	6.40%	385
05/22/07	Monongahela Pow/Potomac Ed.	WV	10.50%	4.83%	567	6.46%	404
05/22/07	Union Electric	MO	10.20%	4.83%	537	6.46%	374
05/23/07	Nevada Power	NV	10.70%	4.86%	584	6.49%	421
05/25/07	Public Service of New Hampshire	NH	9.67%	4.86%	481	6.48%	319
06/05/07	Cascade Natural Gas	OR	10.10%	4.98%	512	6.55%	355
06/13/07	Northern States Power	ND	10.75%	5.20%	555	6.78%	397
06/15/07	Entergy Arkansas	AR	9.90%	5.16%	474	6.76%	314
06/21/07	Pacificorp	WA	10.20%	5.16%	504	6.76%	344
06/22/07	Appalachian Power	WV	10.50%	5.14%	536	6.74%	376
06/28/07	Arizona Public Service	AZ	10.75%	5.12%	563	6.72%	403
06/29/07	Yankee Gas Services	CT	10.10%	5.03%	507	6.62%	348
06/29/07	Public Service of New Mexico	NM	9.53%	5.03%	450	6.62%	291
	2nd Quarter Averages		10.23%	4.96%	526	6.57%	365
07/03/07	Public Service of Colorado	CO	10.25%	5.05%	520	6.65%	360
07/12/07	Granite State Electric	NH	9.67%	5.13%	454	6.72%	295
07/13/07	Arkansas Western Gas	AR	9.50%	5.11%	439	6.70%	280
07/19/07	Delmarva Power & Light	MD	10.00%	5.04%	496	6.63%	337
07/19/07	Potomac Electric Power	MD	10.00%	5.04%	496	6.63%	337
07/24/07	Aquila	NE	10.40%	4.94%	546	6.59%	381
08/01/07	Southern Indiana Gas & Electric	IN	10.15%	4.76%	539	6.62%	353
08/15/07	Southern Indiana Gas & Electric	IN	10.40%	4.69%	571	6.72%	368
08/21/07	Consumers Energy	MI	--	4.60%	--	--	--
08/29/07	Columbia Gas of Kentucky	KY	10.50%	4.57%	593	6.62%	388
09/10/07	Northern States Power - MN	MN	9.71%	4.34%	537	6.47%	324
09/19/07	Washington Gas & Light	VA	10.00%	4.53%	547	6.64%	336
09/25/07	Consolidated Edison of NY	NY	9.70%	4.63%	507	6.65%	305
	3rd Quarter Averages		10.02%	4.80%	520	6.64%	339
10/08/07	Atmos Energy	TN	10.48%	4.65%	583	6.59%	389
10/09/07	Public Service of Oklahoma	OK	10.00%	4.67%	533	6.57%	343
10/18/07	Orange and Rockland Utilities	NY	9.10%	4.52%	458	6.46%	264
10/19/07	Delta Natural Gas	KY	10.50%	4.41%	609	6.38%	412
10/25/07	CenterPoint Energy Resources	AR	9.65%	4.37%	528	6.36%	329
10/31/07	Electric Transmission Texas	TX	9.96%	4.48%	548	6.47%	349
11/15/07	Washington Gas & Light	MD	10.00%	4.17%	583	6.39%	361
11/20/07	Arkansas Oklahoma Gas	AR	9.90%	4.06%	584	6.41%	349
11/27/07	UNS Gas	AZ	10.00%	3.95%	605	6.36%	364
11/29/07	Cheyenne Light, Fuel, & Power	WY	10.90%	3.94%	696	6.40%	450
12/06/07	Kansas City Power & Light	MO	10.75%	4.02%	673	6.61%	414
12/13/07	AEP Central Texas	TX	9.96%	4.18%	578	6.76%	320
12/14/07	Madison Gas & Electric	WI	10.80%	4.24%	656	6.79%	401
12/14/07	South Carolina Electric & Gas	SC	10.70%	4.24%	646	6.79%	391
12/18/07	Northwestern Energy Division	NE	10.40%	4.14%	626	6.66%	374
12/19/07	Avista Corporation	WA	10.20%	4.06%	614	6.60%	360
12/20/07	Duke Energy Carolinas	NC	11.00%	4.04%	696	6.55%	445
12/20/07	Bangor Hydro Electric	ME	10.20%	4.04%	616	6.55%	365
12/21/07	Pacific Gas and Electric	CA	11.35%	4.18%	717	6.68%	467
12/21/07	San Diego Gas & Electric	CA	11.10%	4.18%	692	6.68%	442
12/21/07	Southern California Edison	CA	11.50%	4.18%	732	6.68%	482
12/21/07	Brooklyn Union Gas	NY	9.80%	4.18%	562	6.68%	312
12/21/07	KeySpan Gas East	NY	9.80%	4.18%	562	6.68%	312
12/21/07	National Fuel Gas Distribution	NY	9.10%	4.18%	492	6.68%	242
12/28/07	Pacificorp	ID	10.25%	4.11%	614	6.62%	363
12/31/07	Georgia Power	GA	11.25%	4.04%	721	6.56%	469
	4th Quarter Averages		10.33%	4.19%	612	6.57%	376
	2007 Average		10.23%	4.65%	557	6.52%	371

Source: SNL Financial, Federal Reserve

Figure 46: 2008 Rate Case Outcomes

Date	Company	State	Allowed ROE	10-Year Treas. Yield	Spread (bps)	Moodys Baa Yield	Spread (bps)
01/08/08	Northern States Power Co-WI	WI	10.75%	3.86%	689	6.49%	426
01/08/08	Northern States Power Co-WI	WI	10.75%	3.86%	689	6.49%	426
01/17/08	Wisconsin Electric Power Co.	WI	10.75%	3.66%	709	6.47%	428
01/17/08	Wisconsin Electric Power Co.	WI	10.75%	3.66%	709	6.47%	428
01/17/08	Wisconsin Gas LLC	WI	10.75%	3.66%	709	6.47%	428
01/28/08	Connecticut Light & Power Co.	CT	9.40%	3.61%	579	6.58%	282
01/30/08	Potomac Electric Power Co.	DC	10.00%	3.78%	622	6.72%	328
01/31/08	Central Vermont Public Service	VT	10.71%	3.67%	704	6.63%	408
02/05/08	North Shore Gas Co.	IL	9.99%	3.61%	638	6.62%	337
02/05/08	Peoples Gas Light & Coke Co.	IL	10.19%	3.61%	658	6.62%	357
02/13/08	Indiana Gas Co.	IN	10.20%	3.70%	650	6.81%	339
02/29/08	Fitchburg Gas & Electric Light	MA	10.25%	3.53%	672	6.75%	350
03/12/08	PacifiCorp	WY	10.25%	3.49%	676	6.88%	337
03/25/08	Consolidated Edison Co. of NY	NY	9.10%	3.51%	559	6.90%	220
03/31/08	Avista Corp.	OR	10.00%	3.45%	655	6.90%	310
	1st Quarter Averages		10.26%	3.64%	661	6.65%	360
04/22/08	MDU Resources Group Inc.	MT	10.25%	3.74%	651	6.95%	330
04/24/08	Public Service Co. of NM	NM	10.10%	3.87%	623	7.00%	310
05/01/08	Hawaiian Electric Co.	HI	10.70%	3.78%	692	6.82%	388
05/27/08	UNS Electric Inc.	AZ	10.00%	3.93%	607	7.01%	299
05/28/08	Duke Energy Ohio Inc.	OH	10.50%	4.03%	647	7.06%	344
06/10/08	Consumers Energy Co.	MI	10.70%	4.11%	659	7.05%	365
06/24/08	Atmos Energy Corp.	TX	10.00%	4.10%	590	7.08%	292
06/27/08	Sierra Pacific Power Co.	NV	10.60%	3.99%	661	7.03%	357
06/27/08	Appalachian Power Co.	WV	10.50%	3.99%	651	7.03%	347
06/27/08	Questar Gas Co.	UT	10.00%	3.99%	601	7.03%	297
	2nd Quarter Averages		10.34%	3.95%	638	7.01%	333
07/10/08	Otter Tail Corp.	MN	10.43%	3.83%	660	7.00%	343
07/16/08	Orange & Rockland Utills Inc.	NY	9.40%	3.97%	543	7.21%	219
07/30/08	Empire District Electric Co.	MO	10.80%	4.07%	673	7.24%	356
07/31/08	San Diego Gas & Electric Co.	CA	10.70%	3.99%	671	7.21%	349
07/31/08	San Diego Gas & Electric Co.	CA	10.70%	3.99%	671	7.21%	349
07/31/08	Southern California Gas Co.	CA	10.82%	3.99%	683	7.21%	361
08/11/08	PacifiCorp	UT	10.25%	3.99%	626	7.23%	302
08/26/08	Southwestern Public Service Co.	NM	10.18%	3.79%	639	7.10%	308
08/27/08	SourceGas Distribution LLC	CO	10.25%	3.77%	648	7.07%	318
09/02/08	Chesapeake Utilities Corp.	DE	10.25%	3.74%	651	7.07%	318
09/10/08	Commonwealth Edison Co.	IL	10.30%	3.65%	665	7.02%	328
09/17/08	Atmos Energy Corp.	GA	10.70%	3.41%	729	7.25%	345
09/24/08	Central Illinois Light Co.	IL	10.65%	3.80%	685	7.58%	307
09/24/08	Central Illinois Public	IL	10.65%	3.80%	685	7.58%	307
09/24/08	Illinois Power Co.	IL	10.65%	3.80%	685	7.58%	307
09/24/08	Central Illinois Light Co.	IL	10.68%	3.80%	688	7.58%	310
09/24/08	Central Illinois Public	IL	10.68%	3.80%	688	7.58%	310
09/24/08	Illinois Power Co.	IL	10.68%	3.80%	688	7.58%	310
09/30/08	Avista Corp.	ID	10.20%	3.85%	635	7.85%	235
09/30/08	Avista Corp.	ID	10.20%	3.85%	635	7.85%	235
	3rd Quarter Averages		10.46%	3.83%	662	7.35%	311
10/03/08	New Jersey Natural Gas Co.	NJ	10.30%	3.63%	667	7.98%	232
10/08/08	Puget Sound Energy Inc.	WA	10.15%	3.72%	643	8.21%	194
10/08/08	Puget Sound Energy Inc.	WA	10.15%	3.72%	643	8.21%	194
10/20/08	CenterPoint Energy Resources	TX	10.06%	3.91%	615	9.43%	63
10/24/08	Piedmont Natural Gas Co.	NC	10.60%	3.76%	684	9.30%	130
10/24/08	Public Service Co. of NC	NC	10.60%	3.76%	684	9.30%	130
11/17/08	Appalachian Power Co.	VA	10.20%	3.68%	652	9.26%	94
11/21/08	Southwest Gas Corp.	CA	10.50%	3.20%	730	9.08%	142
11/21/08	Southwest Gas Corp.	CA	10.50%	3.20%	730	9.08%	142
11/21/08	Southwest Gas Corp.	CA	10.50%	3.20%	730	9.08%	142
11/24/08	Narragansett Electric Co.	RI	10.50%	3.35%	715	9.21%	129
12/01/08	Tucson Electric Power Co.	AZ	10.25%	2.72%	753	8.84%	141
12/23/08	Columbia Gas of Ohio Inc	OH	10.39%	2.18%	821	8.12%	227
12/23/08	Detroit Edison Co.	MI	11.00%	2.18%	882	8.12%	288
12/24/08	Southwest Gas Corp.	AZ	10.00%	2.20%	780	8.10%	190
12/26/08	Northwest Natural Gas Co.	WA	10.10%	2.16%	794	8.06%	204
12/29/08	Portland General Electric Co.	OR	10.10%	2.13%	797	8.05%	205
12/29/08	Avista Corp.	WA	10.20%	2.13%	807	8.05%	215
12/29/08	Avista Corp.	WA	10.20%	2.13%	807	8.05%	215
12/31/08	Northern States Power Co. - MN	ND	10.75%	2.25%	850	8.07%	268
	4th Quarter Averages		10.35%	2.96%	739	8.58%	177
	2008 Average		10.35%	3.60%	675	7.40%	295

Source: SNL Financial, Federal Reserve

Figure 47: 1Q09 Rate Case Outcomes

Date	Company	State	Allowed ROE	Yield on 10-Year Treasury	Spread (bps)	Yield on Moodys Baa	Spread (bps)
01/14/09	Public Service of Oklahoma	OK	10.50%	2.24%	826	7.92%	258
01/21/09	Toledo Edison Co.	OH	10.50%	2.56%	794	8.14%	236
01/21/09	Ohio Edison Co.	OH	10.50%	2.56%	794	8.14%	236
01/21/09	Cleveland Electric Illuminating Co	OH	10.50%	2.56%	794	8.14%	236
01/27/09	Union Electric Co.	MO	10.76%	2.59%	817	8.06%	270
01/30/09	Idaho Power Co.	ID	10.50%	2.87%	763	8.25%	225
02/04/09	United Illuminating Co.	CT	8.75%	2.95%	580	8.24%	51
03/04/09	Indiana Michigan Power	IN	10.50%	3.01%	749	8.32%	218
03/12/09	Southern California Edison	CA	11.50%	2.89%	861	8.41%	309
03/17/09	Tampa Electric Co.	FL	8.11%	3.02%	509	8.62%	(51)
01/13/09	Michigan Gas Utilities Corp.	MI	10.45%	2.33%	812	8.05%	240
02/02/09	New England Gas Co.	MA	10.05%	2.76%	729	8.09%	196
03/09/09	Atmos Energy Corp.	TN	10.30%	2.89%	741	8.29%	201
03/25/09	Northern Illinois Gas Co.	IL	10.17%	2.81%	736	8.60%	157
1st Quarter Averages			10.22%	2.72%	750	8.23%	199

Source: SNL Financial, Federal Reserve

Figure 48: Electricity Rates, by Customer Class

(cents / kWh)

State	Residential	Commercial	Industrial	Total / Avg.
Idaho	6.97	5.67	4.55	5.66
West Virginia	7.02	6.02	4.17	5.54
North Dakota	7.54	6.74	5.54	6.65
Washington	7.57	6.73	4.8	6.6
Kentucky	7.71	7.12	4.84	6.16
Nebraska	7.87	6.59	5.12	6.53
Missouri	8.01	6.6	4.98	6.84
Wyoming	8.16	6.67	4.52	5.67
South Dakota	8.26	6.81	5.31	7.07
Utah	8.37	6.8	4.7	6.61
Oregon	8.54	7.63	4.93	7.27
Tennessee	8.55	8.74	6.14	7.84
Indiana	8.76	7.67	5.49	7.01
Montana	9.16	8.48	6.4	8
Kansas	9.17	7.7	NM	7.7
Oklahoma	9.45	8.21	6.08	8.13
Arkansas	9.49	7.73	5.98	7.74
Virginia	9.55	7.24	5.54	7.87
Minnesota	9.61	7.82	5.99	7.77
Iowa	9.66	7.24	4.9	6.99
North Carolina	9.68	7.64	5.59	8.06
South Carolina	9.98	8.48	NM	7.87
New Mexico	10.02	8.65	6.45	8.38
Ohio	10.13	9.19	6.19	8.39
Georgia	10.14	9.18	6.69	8.95
Colorado	10.17	8.65	6.63	8.64
Alabama	10.24	9.7	6.02	8.45
Mississippi	10.34	9.96	6.46	8.92
Arizona	10.35	8.95	6.69	9.21
Louisiana	10.55	10.29	8.12	9.59
Illinois	10.82	8.78	NM	8.95
Michigan	10.88	9.42	6.87	9.11
U.S. Total	11.34	10.33	7.01	9.81
Wisconsin	11.44	9.19	6.52	8.93
Pennsylvania	11.47	9.41	7.04	9.36
Florida	11.6	10.06	8.27	10.7
Nevada	11.87	10.14	8.23	10.02
District of Columbia	12.64	13.76	11.55	13.56
Texas	12.94	10.8	8.97	11.07
Maryland	13.67	12.79	10.46	12.94
Delaware	13.88	12.04	10.25	12.28
California	14.37	13.12	10.28	13
Vermont	14.6	12.5	9.01	12.31
New Hampshire	15.58	14.2	13.12	14.54
Maine	15.98	12.99	11.88	13.72
New Jersey	16.01	14.9	12.55	15.04
Alaska	16.35	13.14	14.26	14.45
Rhode Island	17.26	15.25	14.08	15.88
Massachusetts	17.38	16.1	14.41	16.24
New York	18.56	16.96	10.28	16.75
Connecticut	19.29	15.96	13.8	16.88
Hawaii	32.73	29.97	26.33	29.46

Source: EIA.

Figure 49: Ranking of State Utility Commissions

Commission	Raw Score	Rank	JD Power Score
Kentucky Public Service Commission	7.29	1	710
Wyoming Public Service Commission	7.29	1	
Iowa Utilities Board	7.32	3	708
Idaho Public Utilities Commission	7.39	4	
North Carolina Utilities Commission	7.57	5	719
Florida Public Service Commission	7.86	6	700
Minnesota Public Utilities Commission	7.93	7	698
Ohio Public Utilities Commission	7.96	8	668
Alabama Public Service Commission	8.00	9	723
Colorado Public Utilities Commission	8.00	9	694
Georgia Public Service Commission	8.00	9	723
Oklahoma Corporation Commission	8.04	12	697
Texas Public Utility Commission	8.04	12	658
Michigan Public Service Commission	8.11	14	677
North Dakota Public Service Commission	8.11	14	
California Public Utilities Commission	8.18	16	681
Indiana Utility Regulatory Commission	8.25	17	669
Kansas Corporation Commission	8.29	18	653
South Carolina Public Service Commission	8.32	19	703
Wisconsin Public Service Commission	8.39	20	693
Arkansas Public Service Commission	8.46	21	654
Virginia State Corporation Commission	8.46	21	679
Delaware Public Service Commission	8.50	23	654
Massachusetts Dept of Tele and Energy	8.61	24	650
Oregon Public Utility Commission	8.64	25	691
Washington Utils and Trans Commission	8.64	25	677
Utah Public Service Commission	8.75	27	678
Hawaii Public Utilities Commission	8.79	28	
Illinois Commerce Commission	8.86	29	617
District of Columbia Public Svc Commission	8.93	30	654
West Virginia Public Service Commission	8.93	30	
Mississippi Public Service Commission	8.96	32	689
Missouri Public Service Commission	8.96	32	653
South Dakota Public Utilities Commission	8.96	32	636
Nevada Public Utilities Commission	9.18	35	639
Louisiana Public Service Commission	9.36	36	682
Vermont Public Service Board	9.39	37	
New Jersey Board of Public Utilities	9.68	38	659
Maine Public Utilities Commission	9.71	39	677
Pennsylvania Public Utility Commission	9.89	40	691
New Hampshire Public Utilities Commission	9.93	41	646
Maryland Public Service Commission	10.00	42	623
New York Public Service Commission	10.04	43	645
Rhode Island Public Utilities Commission	10.07	44	646
Connecticut Department of Pub Utility Control	10.32	45	641
Arizona Corporation Commission	10.46	46	698
Montana Public Service Commission	10.50	47	636
New Mexico Public Regulation Commission	10.57	48	667

Source: SNL Financial, JD Power & Associates, Barclays Capital estimates.

Figure 50: State Regulatory Staff Contacts

<u>STATE</u>	<u>NAME</u>	<u>POSITION</u>	<u>PHONE</u>	<u>E-MAIL</u>
Alabama	Janice Hamilton	Director, Energy Division	344-242-2696	janice.hamilton@psc.alabama.gov
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	Rebecca Wilder	Public Information Officer	602-542-0844	
Arkansas	Ernest G. Johnson	Director, Utilities Division	602-542-4251	
	John Bethel	Executive Director - General Staff	501-682-1794	
California	Lynn Carew	General Staff Information Number	501-682-1794	
	Paul Clanon	Chief, ALJ Division	415-703-1721	
	Sean Gallagher	Executive Director	415-703-3808	
Colorado	Barbara Fernandez	Chief of Staff	303-894-2012	
	Doug Dean	Director	303-894-2007	
	Eugene Camp	Section Chief, Energy	303-894-2047	
Connecticut	Media Spokesperson	Media Relations/Public Information	860-827-2670	
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	Tom Bond	Public Information Officer	404-651-9401	
Hawaii	Paul Shigenaga	Director of Utilities	808-586-2028	
	Joan Yamaguchi	Administrative Director	808-586-2044	
	Stacy Djou	Administrator - Utilities Division	808-586-2022	
Idaho	Randy Lobb	Chief Counsel	208-334-0350	randy.lobb@puc.idaho.gov
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	Joseph Sutherland	Public Information Officer	317-232-2297	
	Brad Borum	Executive Director, Public Information	317-232-2304	
Iowa	Judie Cooper	Director of Electricity	515-281-5386	
	Jeff Kaman	Executive Secretary	515-281-3279	
Kansas	Rob Hillesland	Energy Section	515-281-3551	
	Susan Cunningham	Information Specialist	785-271-3272	
	Don Low	General Counsel	785-271-3221	
Kentucky	Rosemary Foreman	Director, Utilities Division	785-271-3275	
Louisiana	Stephanie Stumbo	Public Spokesperson	502-564-3940 ext. 264	eve.gonzalez@ia.gov
	Lawrence St. Blanc	Executive Director	225-342-4416	arnold.chauviere@ia.gov
	Arnold Chauviere	Deputy Assistant Secretary, Utilities	225-342-4416	
	Stan Perkins	Audit Director	225-342-1438	
Maine	Brian McManus	Economist Director	225-342-2720	
	Richard Kivela	Utility Analyst	207-287-1662	richard.kivela@maine.gov
	Fred Bever	Public Information Coordinator	207-287-6141	chris.simpson@maine.gov
Maryland	Gregory V. Carmean	Executive Director	410-767-8002	
	Obi Linton	External Relations, Director	410-767-8028	
Massachusetts	Timothy Shevlin	Executive Director	617-305-3691	
	Mary Cottrell	Secretary	617-305-3600	
Michigan	Robert Kehres	Regulatory Affairs Division, Director	517-241-6016	kehres@michigan.gov
	Mary Jo Kunkle	Regulatory Affairs Division, Executive Secretary	517-241-3322	kunklem@michigan.gov
Minnesota	Earl Haar	Executive Secretary	651-201-2222	
	Janet Gonzales	Supervisor, Energy	651-201-2231	
Mississippi	Brian U. Ray	Executive Secretary	601-961-5434	brian.ray@psc.state.ms.us
	George Haynie	Central District Chief of Staff	601-961-5430	george.haynie@psc.state.ms.us
	Thomas Adams	Northern District Chief of Staff	662-993-1471	thomas.adams@psc.state.ms.us
	Jay McKnight	Southern District Staff Officer	228-396-2643	jay.mcknight@psc.state.ms.us
Missouri	Bob Shallenberg	Staff	573-751-7162	bob.shallenberg@psc.mo.gov
	Kevin Kelly	Public Information Officer	573-751-9300	kevin.kelly@psc.mo.gov
Montana	Kate Whitney	Administrator - Utilities Division	406-444-3056	kwhitney@mt.gov
New Hampshire	Debra Howland	Executive Director	603-271-2431	
New Jersey	Doyle Siddell	Public Information Officer	973-648-6135	
	Victor Fortkiewicz	Executive Director	973-648-4852	
	Mark Beyer	Chief Economist	973-648-3414	
	Kristi Izzo	Secretary	973-648-3426	
New Mexico	Daniel Mayfield	Chief of Staff	505-827-4433	daniel.mayfield@state.nm.us
	Roy Stephenson	Utilities Division Director	505-827-6960	
	Mona Varela	Management Analyst, Office of the Chief of Staff	505-827-4433	
Nevada	Sean Sever	Public Information Officer	775-684-6118	ssever@puc.state.nv.us
	Kirby Lampley	Director of Regulatory Operations	775-684-6137	klampley@puc.state.nv.us
New York	Debra Renner	Director, Office of Administration	518-474-2508	
	Tom Dvorsky	Director, Electric, Gas & Water	518-473-6080	
	Judith Lee	Acting Executive Deputy	518-474-4620	
North Carolina	George Sessoms	Deputy Director, Electric and Telecom	919-715-5292	sessoms@ncuc.net
	Robert Bennink, Jr.	Dir. Adm. Division and General Counsel	919-733-0833	bennink@ncuc.net
	Renne Vance	Chief Clerk	919-733-0840	vance@ncuc.net
North Dakota	Ilona Jeffcoat	Director of Public Utilities Division	701-328-2407	
Ohio	Stephen Brennan	Director, Utilities Department	614-466-3705	
	Shana Gerber	Communications Liaison	614-995-4168	
Oklahoma	Renne Jenkins	Commission Secretary	614-995-4294	
	David Dykeman	Director, Public Utility Division	405-521-2322	
Oregon	Andrew Tevington	Deputy Director, Public Utility Division	405-521-6953	
	Bonnie Tatom	Electricity Division, General Info	503-378-8225	Bonnie.Tatom@state.or.us
	Judy Johnson	Electricity Division, General Info and Rate Cases	503-378-6636	Judy.Johnson@state.or.us
Pennsylvania	Karen O'Maury	Director of Operations	717-772-8883	
	Tom Charles	Manager of Communications	717-787-9504	thcharles@state.pa.us
Rhode Island	Luly Massaro	Commission Clerk	401-941-4500, x107	
	Sharon Colby Camara	Chief Financial Analyst	401-941-4500, x157	
	Thomas Kogut	Chief of Information	401-941-4500, x105	
South Carolina	Charles Terreni	Chief Clerk and Administrator	803-896-5133	
	Philip Riley	Energy Advisor	803-896-5154	
South Dakota	Greg Rislov	Commission Advisor	605-773-3201	greg.rislov@state.sd.us
	Patricia Van Gerpen	Executive Director	605-773-3201	patty.vangerpen@state.sd.us
Tennessee	Darlene Standley	Utilities Division, Chief	615-741-2904, x149	darlene.standley@tn.gov
	Jessica Johnson	Office of Public Information	615-741-2904, x233	jessica.johnson@tn.gov
Texas	Jess Totten	Dir. Electric Division	512-936-7235	jess.totten@psc.state.tx.us
	Becky Wilson	Executive Staff Director, Electric & Gas	801-530-6770	rwilson@utah.gov
Utah	Julie P. Orchard	Commission Administrator	801-530-6713	jorchard@utah.gov
Vermont	Tamera Pariseau	Coordinator of Public Information Division	802-828-5262	tamera.pariseau@state.vt.us
	Judy Bruneau	Administrative Secretary	802-828-4071	judy.moody@state.vt.us
Virginia	Howard Spinner	Director, Division of Economics and Finance	804-371-9449	econfin@sec.virginia.gov
	William F. Stephens	Director, Division of Energy	804-371-9611	energyreg@sec.virginia.gov
	Kenneth Schrad	Director, Information Services	804-371-9141	ken.schrad@sec.virginia.gov
Washington	Anne Solwick	Director, General Utility Regulation	360-664-1290	asolwick@utc.wa.gov
	David Danner	Executive Director	360-664-1208	ddanner@utc.wa.gov
	Marilyn Meehan	Information Officer	360-664-1116	mmeehan@utc.wa.gov
	Mike Parvinen	Assistant Director, Electricity and Gas	360-664-1315	mparvinen@utc.wa.gov
West Virginia	Cheryl Ranson	Director, Utilities Division	304-340-0421	
	Dixie Kelmeyer	Supervisor, Energy Section	304-340-0762	
	Sandra Squire	Executive Secretary	304-340-0426	
Wisconsin	Robert Norcross	Administrator, Electric Division	608-266-0699	robert.norcross@psc.state.wi.us
Wyoming	Darrell Zlomke	Supervisor/Assistant Administrator	307-777-5724	dzmok@state.wy.us
	Denise Parrish	OCA Deputy Administrator	307-777-5743	dparr@state.wy.us
	Mary Kiser	Docketing Clerk	307-777-5749	mkiser@state.wy.us

Source: SNL Financial

Figure 51: State Regulatory Commissioners, A-M

STATE	NAME	Party	Term Ends	Experience	Contact Name	PHONE	E-MAIL
Alabama	Chair Lucy Baxley	D	Nov-12	President of Sullivan Furniture Inc.; private law practice	Lisa Parrish	334-242-5297	Lisa.parrish@psc.alabama.gov
	Susan Parker	D	Nov-10	Retired educator and former state auditor.	Brad Williams	344-242-5191	brad.williams@psc.alabama.gov
	Jan Cook	D	Nov-10	Alabama State Auditor for eight years	Kelly Mulero	344-242-5203	Jan.cook@psc.alabama.gov
Arizona	Chair Kristin K. Mayes	R	Jan-11	State Rep., Chmn. Natural Res. and Agric. Committee		602-542-4143	Mayes-web@azcc.gov
	Gary Pierce	R	Jan-11	state representative (Majority Whip)		602-542-3933	Pierce-web@azcc.gov
	Bob Stump	R	Jan-13	Attorney, State legislator; Municipal Court Judge		602-542-3935	Stump-web@azcc.gov
	Paul Newman	D	Jan-13	Attorney, Gov. Communications Director; Reporter		602-542-3682	Newman-web@azcc.gov
	Sandra Kennedy	D	Jan-13	State Representative, Chairman Energy, Utilities, & Technology Committee		602-542-3625	Kennedy-web@azcc.gov
Arkansas	Chair Paul Suskie	D	Jan-13	North Little Rock City Attorney, Major in National Guard (JAG)		501-682-5809	
	Olan Reeves	R	Jan-15	Attorney; PSC Staff Director; Governor's Liaison; Asst. General Counsel, Arkla		501-682-5809	
	Colette Honorable	D	Jan-11	Inker; Gov's Budget Director; Gov's Economic Development Policy Advisor; various positions at Department of Higher Education		501-682-5809	
California	Pres. Michael R. Peevy	D	Jan-15	CEO of TruePricing Inc.; Pres. of New Energy Inc.; Pres. of Edison Int'l. and Southern California Edison		415-703-3703	
	Dian Grueneich	D	Jan-11	Energy and Environmental Law Consultant; Attorney	Theresa Cho	415-703-2682	
	Rachelle Chong	R	Jan-15	Attorney, FCC Commissioner; private practice attorney, mediator arbitrator	Lynn Carew	415-703-3700	
	John Bohn	R	Jan-11	Businessman; President and CEO of Moody's; Special Assistant to former U.S. Treasury Secretary Regan		415-703-2440	
	Timothy Alan Simon	R	Jan-13	Appointments Secretary in Gov. Office; General counsel and chief compliance officer for various US Corporations	Alan Reynolds	415-703-1407	
Colorado	Chair Ron Binz	D	Jan-11	Consultant; Director of the Office of Consumer Counsel		303-894-2000	pucc@dora.state.co.us
	James Tarpey	R	Jan-13	County Commissioner; Chair, Denver Regional Council of Governm		303-894-2000	pucc@dora.state.co.us
	Matt Baker	D	Jan-12	State Representative; Lake County Commissioner; U.S. Army		303-894-2000	pucc@dora.state.co.us
Connecticut	Chair Donald W. Downes	R	Jun-09	Attorney; Deputy Secretary of State Office of Policy and Management		860-827-2801	
	Kevin M. DeGobbo	R	Jun-11	Private law practice; newspaper reporter		860-827-2802	
	Amalia Vazquez Bzdrya	R	Jun-11	Governor's Special Counsel on Energy; Chief Legal Counsel to Governor		860-827-2802	
	John W. Betkoski	D	Jun-09	State legislator; House Chair of the Joint Commerce Committee		860-827-2802	
	Anthony J. Palermo	D	Jun-11	Private law practice; Consulting		860-827-2802	
Delaware	Chair Armetta McRae	D	May-06	Attorney; Trademark and copyright counsel to E.I. DuPont de Nemours.	Karen Nickerson	302-739-4247	karen.nickerson@state.de.us
	Dallas Winslow	R	May-10	Attorney; Chief of legal services for State Public Defender; Private Law Practice	Karen Nickerson	302-739-4247	karen.nickerson@state.de.us
	James Bruce Lester	R	May-12	Manager, Richland Farms	Karen Nickerson	302-739-4247	karen.nickerson@state.de.us
	Joann Conaway	D	May-12	Realtor	Karen Nickerson	302-739-4247	karen.nickerson@state.de.us
	Jeffrey J. Clark	D	May-09	Attorney; U.S. Army Captain	Karen Nickerson	302-739-4247	karen.nickerson@state.de.us
District of Columbia	Chair Betty Anne Kane	D	Jun-10	Attorney; Acting Deputy Director of the D.C. Office of Labor Relations and Collective Bargaining		202-626-5125	bakane@psc.dc.gov
	Richard E. Morgan	D	Jun-11	Energy Analyst U.S. EPA; PSC Staff member		202-626-0518	rmorgan@psc.dc.gov
	Lori Murphy Lee	D	Jun-12			202-626-5115	llee@psc.dc.gov
Florida	Chair Matthew M. Carter II	R	Jan-10	Attorney; Baptist Minister; US Army	Lois Graham	850-413-6036	Chairman@psc.state.fl.us
	Katrina J. McMurrin	R	Jan-10	Advisor to PSC Commissioners; PSC Division of Policy Analysis	Kay Posey	850-413-6024	Commissioner.McMurrin@psc.state.fl.us
	Lisa Polak Edgar	I	Jan-13	Attorney; Deputy Secretary for Dept. of Environmental Protection; Gov. Office of Policy and Budget	Kelly McLanahan	850-413-6018	Commissioner.Edge@psc.state.fl.us
	Nathan Skop	R	Jan-11		Cristina Slaton	850-413-6030	Commissioner.Skop@psc.state.fl.us
	Nancy Argenziano	R	Jan-11		Steve Larson	850-413-6004	Commissioner.Argenziano@psc.state.fl.us
Georgia	Doug Everett	R	Dec-14	Real estate developer		404-656-4501	deverett@psc.state.ga.us
	Stan Wise	R	Dec-12	Insurance business owner; county commissioner; Atlanta Regional Commission member		404-656-4501	stanwise@psc.state.ga.us
	Lauren McDonald	R	Dec-14	Business Recruiter, assistant administrator of a medical complex at a children's home		404-656-4501	lmcDonald@psc.state.ga.us
	Chuck Caton	R	Dec-12	Member of State House of Representatives; City Commissioner for Albany, GA		404-656-4501	ccaton@psc.state.ga.us
	Bobby Baker	R	Dec-10	Attorney, Gwinnett County Planning Commissioner		404-656-4501	bbaker@psc.state.ga.us
Hawaii	Chair Carlito P. Caliboso	R	Jun-10	Attorney; Partner, private practice		808-586-2020	
	John E. Cole	R	Jun-12	Attorney; Executive Director Division of Consumer Advocacy/Governor's Policy Team		808-586-2020	
	Leslie Kondo	R	Jun-14			808-586-2020	
Idaho	Pres Mack A. Redford	R	Jan-13	Chair of the Legislative Task Force on the Federal Telecommunications Act of 1996; Distance Learning Director of Boise State University		208-334-0338	
	Marsha H. Smith	D	Jan-15	Idaho Deputy Attorney General; PUC Director of Policy and External Relations		208-334-0338	
	Jim Kempton	R	Jan-11	Attorney; general counsel for several engineering firms; Deputy Attorney General		208-334-0338	
Illinois	Chair Charles E. Box	D	Jan-09	Attorney; private consultant; Mayor, Rockford, IL		217-782-7907	
	Lula M. Ford	D	Jan-13	Asst. Dir. Central Management Services; Chicago School's Educ. Liaison to Housing Authority; Teacher		217-782-7907	
	Robert F. Lieberman	D	Jan-10	CFO Private Technology Firm; Positions at Illinois Office of Coal Development and Dept. of Natural Resources		217-782-7907	
	Erin M. O'Connell-Diaz	I	Jan-13	Attorney; Manager Chicago Office of ICC Administrative Law Judges (ALJs) Div.; ALJ; Asst. Attorney General		217-782-7907	
	Sherman Elliott	R	Jan-12			217-782-7907	
Indiana	Chair David L. Hardy	R	Apr-10	Attorney, private practice		317-232-2701	
	David Ziegner	D	Apr-11	Attorney; URC General Counsel; Staff attorney, Indiana Legislative Services Agency		317-232-2701	
	Greg D. Server	R	Apr-09	Member, State Legislature; Dir. Administration, Evansville Water & Sewer Utility		317-232-2701	
	Larry Landis	R	Jan-12	President of marketing and communications firm; experience in advertising and software development		317-232-2701	
	Jeffery Gole	D	Jan-10	Director, Indiana Bureau of Motor Vehicles and Indiana Dept. of Workforce Development; public affairs manager for Kroger Company		317-232-2701	
Iowa	Chair Rob Bernstein	D	Apr-15	Attorney; Chief of Staff for Governor, Congressman; State Chairman, Iowa Democratic Party		515-281-5167	
	Krista Tanner	D	Apr-11	Attorney, private practice; positions at Qwest; IUB legislative liaison		515-281-3941	
	Darrell Hanson	R	Apr-13			515-281-3941	
Kansas	Chair Thomas Wright	D	Mar-10	General Counsel for KCC, Kansas Insurance Dept.; State Representative; Adjunct Professor		785-271-3166	public.affairs@kcc.state.ks.us
	Michael Moffet	R	Mar-08	State Committee on Commerce, Science & Transportation, Aviation Subcommittee; various positions, Federal Aviation Administration		785-271-3350	public.affairs@kcc.state.ks.us
	Joe Harkins	D	Mar-11	Attorney; Private practice		785-271-3350	public.affairs@kcc.state.ks.us
Kentucky	Chair David Armstrong	D	Jun-11	Attorney; Immediate Past President, Southeastern Association of Regulatory Utility Commissioners		502-564-3940	psc.info@ky.com
	John W. Clay	R	Jun-09	Deputy Secretary of the EPPC; Executive Director of the Office of Alcohol Beverage Control in Kentucky's Dept. of Public		502-564-3940	psc.info@ky.com
	James Gardner	D	Jun-12			502-564-3941	psc.info@ky.com
Louisiana	Chair Lambert C. Boissiere	D	Dec-10	Attorney; member of various civic organizations; Board Member of Parish National Bank		225-342-6687/504-680-9529	alicec@lpsc.org
	Eric Skmetta	R	Dec-14	State legislator; businessman	Janet Cahanin	985-624-4660	janetc@lpsc.org
	James M. Field	R	Dec-12	Attorney, NFL contract advisor	Peggy Lantrip	225-342-6900	peggy.lantrip@la.gov
	Foster L. Campbell Jr.	D	Dec-14	State legislator; Insurance agent; Farmer		318-676-7464	foster.campbell@la.org
	Clyde Holloway	R	Dec-10	New Orleans City Constable		337-457-7395	joannd@lpsc.org
Maine	Chair Sharon Reishus	D	Mar-09	Chief Legal Counsel to Gov. Baldacci; Attorney		207-287-3831	maine.puc@maine.gov
	Vendean Vafiades	I	Mar-13	Energy consultant; PUC Staff analyst		207-287-3831	maine.puc@maine.gov
	Jack Cashman	D	Mar-11			207-287-3831	maine.puc@maine.gov
Maryland	Chair Douglas Nazarian	D	Jun-13	Attorney; Exec. Vice President Amerigroup Corp.; commissioner Maryland Insurance Administration		410-767-8073	
	Harold Williams	D	Jun-12	Dir., Corp. Procurement for Baltimore Gas & Electric		410-767-8116	
	Allen M. Frefeld	D	Jun-09	Attorney; PSC Staff Counsel and Hearing Examiner		410-767-8072	
	Susanne Brogan	D	Jun-11			410-767-8072	
	Lawrence Brenner	D	Jun-10	Attorney; Member House of Delegates; Mayor of Aberdeen		410-767-8017	
Massachusetts	Chair Paul Hibbard	D	Jan-11	Chief of Staff Mass. Dept. of Business and Technology		617-305-3500	
	Tim Woolf	D	Jan-11	Energy division of General Electric; Consultant for Deloitte; Project Manager with Georgia Power		617-305-3500	
	Jollette Westbrook	R	Apr-13	Manager Government Relations, Tenneco; Consultant		617-305-3500	
Michigan	Chair Orjia Kor Isigou	D	Jul-13	Assistant Attorney General and Head of the Special Litigation Div. of the MI Attorney General's Office		517-241-6200	
	Stephen Transteth	I	Jul-09	Dep. Dir. Governor's Legislative Affairs Division; Analyst for Senate Democratic Office		517-241-6180	
	Monica Martinez	D	Jul-11	former Gov. Engler's Deputy Legal Counsel; Regulatory Affairs Advisor to MI House Republicans; other legislative aid positions		517-241-6180	
Minnesota	Chair David C. Boyd	R	Jan-15	Dairy farmer; State Legislator, including Assistant House Minority Leader and House Republican Whip		651-201-2200	David.C.Boyd@state.mn.us
	Phyllis Reha	D	Jan-13	Attorney; Member of MN House of Representatives (1989-2004) and House Minority Leader (1996-2002)		651-201-2200	Phyllis.Reha@state.mn.us
	Thomas W. Pugh	D	Jan-11	Chief Administrative Law Judge; Deputy Commissioner/Assistant Comm. at Minnesota DPS		651-201-2200	Tom.Pugh@state.mn.us
	Dennis O'Brien	R	Jan-14	Consultant to the Econ. Development Div. of the Iron Range Resources and Rehab. Board; business exec.		651-201-2200	Dennis.O'Brien@state.mn.us
	Betsy L. Wergin	R	Jan-10			651-201-2200	Betsy.Wergin@state.mn.us
Mississippi	Chair Lynn Posey	D	Dec-11	Mississippi House of Representatives; PSC Utility Investigator, Harris County Dep. Sheriff		601-961-5430	central.district@psc.state.ms.us
	Brandon Presley	D	Dec-11	Mississippi House of Representatives; Monroe County Sheriff		601-961-5450	northern.district@psc.state.ms.us
	Leonard L. Bentz	R	Dec-11	Mississippi House of Representatives; PSC Utility Investigator, Harris County Dep. Sheriff		601-961-5440	southern.district@psc.state.ms.us

Source: SNL Financial

Figure 52: State Regulatory Commissioners, M-W

Missouri	Robert Clayton III	D	Apr-09	Attorney; various positions in state government	573-751-4221	robert.clayton@psc.mo.gov
	Terry Jarrett	R	Sep-13	Attorney; Missouri House of Representatives	573-751-3243	terry.jarrett@psc.mo.gov
	Kevin Gunn	D	Mar-14	Attorney; Speaker, Missouri House of Representatives; City Prosecutor	573-751-0946	kevin.gunn@psc.mo.gov
Montana	Jeffrey Davis	R	Apr-12	Attorney; Missouri House of Representatives	573-751-3233	jeff.davis@psc.mo.gov
	Chair Greg Jergeson	D	Jan-11	State Senator; Montana State University-Northern Foundation; Farmer	406-444-6199	gjerjeson@mt.gov
	John Vincent	D	Jan-13	State Legislator	406-444-6199	jvincent@mt.gov
	Gail Gutsche	D	Jan-13	Speaker, State House of Representatives	406-444-6199	ggutsche@mt.gov
	Brad Mohar	R	Jan-13	State Legislator; Building contractor	406-444-6199	bmohar@mt.gov
Nebraska	Ken Toole	D	Jan-11	State Senator and Montana Caucus Chair of the Northwest Energy Coalition.	406-444-6199	ktoole@mt.gov
	Frank Landis	R	Jan-13		800-526-0017	frank.landis@nebraska.gov
	Gerald Vap	R	Jan-11		800-526-0017	jerry.vap@nebraska.gov
	Anne Boyle	D	Jan-15		800-526-0017	anne.boyle@nebraska.gov
	Tim Schram	R	Jan-13		800-526-0017	tim.schram@nebraska.gov
	Rod Johnson	R	Jan-11		800-526-0017	rod.johnson@nebraska.gov
New Hampshire	Chair Thomas Getz	D	Jun-13	Attorney, PUC Executive Director; Counsel for electric utility, Staff member of New York Public Service Commission	603-271-2431	TOM.GETZ@PUC.NH.GOV
	Graham J. Morrison	R	Jun-09	Vice President Marketing at Novilt, Inc., various positions at U.S. corporations	603-271-2431	GRAHAM.MORRISON@PUC.NH.GOV
	Clifton Below	D	Jun-11	Member of State House of Representatives and Senate; Commercial real estate developer	603-271-2290	CLIFTON.BELOW@PUC.NH.GOV
New Jersey	Pres. Jeanne M. Fox	D	Mar-14	onal Administrator; Deputy Commissioner, NJ Dept. Environmental Protection & Energy; Dir. BPU Div. Water & Waste Water Services	973-648-2350	
	Elizabeth Randall	R	Mar-13	Gov's Chief of Management & Policy; Deputy Commissioner, NJ Dept. of Labor	973-648-2350	
	Joseph L. Fiordaliso	D	Mar-10	Dep. Chief of Staff for former Gov. Richard Codey, Mayor, Livingston, NJ; Essex County Executive	973-648-2350	
	Frederick Butler	D	Mar-09	Executive Dir., Dem. Office of NJ General Assembly; Dir., Budget & Fiscal Analysis for NJ General Assembly	973-648-2350	
	Nicholas Asselta	R	Mar-14	Attorney in private practice; Commissioner, NJ Highway Authority	973-648-2350	
New Mexico	Chair Sandy Jones	D	Dec-10	Health care consultant	505-827-8020	Elizabeth.Martin@state.nm.us
	Carol Sloan	D	Dec-10	Served as McKinley County Clerk.	505-827-8019	Luis.Ledezma@state.nm.us
	Jerome Block Jr.	D	Dec-12	Administrative Services Dir., CRD state Dept. of Cultural Affairs	505-827-4533	charlotte.duran1@state.nm.us
	David King	R	Dec-10	New Mexico State University CFO; State Treasurer	505-827-4531	Stacey.Starr-Garcia@state.nm.us
	Jason Marks	D	Dec-12	Chairman State Fair Commission; has run his own construction business.	505-827-8015	Leroy.Aragon@state.nm.us
Nevada	Chair Jo Ann Kelly	I	Sep-09	CPA; Commissioner (1985-1996); Temporary Commissioner (2000)	775-684-6101	cjackson@puc.state.nv.us
	Rebecca Wagner	R	Sep-11	Gov. Guinn's Energy Advisor; PUC Public Information Officer	775-684-6101	cjackson@puc.state.nv.us
	Samuel Thompson	R	Sep-12		775-684-6101	cjackson@puc.state.nv.us
New York	Chair Garry A. Brown	R	Feb-09		518-474-7080	
	Maureen F. Harris	R	Feb-12	Attorney in private practice; Asst. Attorney General	518-474-7080	
	Robert E. Curry Jr.	I	Feb-12	Attorney	518-474-7080	
	James Larocca	D	Feb-12	Chairman, New York State Pricing and Wagering Board	518-474-7080	
	Patricia Acampora	R	Feb-09	Member New York Assembly; Asst. to Suffolk County Executive	518-474-7080	
North Carolina	Edward S. Finley	D	Jun-11		919-733-0829	
	Robert V. Owens Jr.	D	Jun-13	Dare County Board of Commissioners; Director of the Governor's Eastern Office; restaurant owner	919-733-4071	
	Susan Rabon	D	Jun-15	State Senator; Secretary of Dept. of Natural Resources; Mayor of Chapel Hill (NC)	919-733-4249	
	Bryan Beatty	D	Jun-09	Attorney in private practice	919-733-0825	
	Lorinzo Little Joyner	D	Jun-09	Government Attorney, including a Staff Attorney for the Public Staff of the NCUC	919-733-0826	
	William T. Culpepper	D	Jun-13	North Carolina House of Representatives; Attorney	919-733-0828	
North Dakota	Chair Kevin Cramer	R	Dec-10	President of the Bismarck School Board; Licensed Social Worker; Certified Consumer Credit Counselor	701-328-2400	krcramer@nd.gov
	Brian Kalk	R	Dec-14	Director of a Leadership Foundation at the University of Bismarck	701-328-2400	bkalk@nd.gov
	Anthony Clark	R	Dec-12	State Labor Commissioner; state legislator	701-328-2400	tdclark@nd.gov
Ohio	Chair Alan R. Schriber	I	Apr-14	Economist; Former owner of several radio stations; PUC Commissioner (1983-1989); economics professor	614-466-3204	
	Cheryl Roberto	D	Apr-13	Attorney; Deputy Dir., Div. of Oil and Gas of Ohio Dept. of Natural Resources; Mayor of Zanesville, Ohio	614-466-3905	
	Valerie A. Lemmie	I	Apr-11	Kettering Research Foundation; Cincinnati City Manager; U.S. Dept. Consumer & Regulatory Affairs	614-466-3101	
	Paul Centolella	D	Apr-12	Toledo City Council; Toledo Metropolitan Council of Governments; Ohio School Boards Association	614-464-8213	
	Ronda H. Fergus	R	Apr-10	Attorney; PUC Chief of Telecommunications	405-521-2261	
Oklahoma	Chair Bob Anthony	R	Jan-13	Attorney; various state government positions; petroleum landman.	405-521-2267	Jackie.Hollinhead
	Dana Murphy	R	Jan-11	President, Independent Petroleum Association of America; Staff of U.S. Senator David Boren	405-521-2264	Billie.Rodley
	Jeff Cloud	R	Jan-15	Formerly President/Chairman of C.R. Anthony (clothing retailer) that is no longer in business	503-378-6611	Lisa.Roberts
Oregon	Chair Lee Beyer	D	Mar-12	State Senator; State Representative	503-378-6611	
	John Savage	D	Mar-09	Director of PUC Utility Program; Director of Oregon Department of Energy	503-378-6611	
	Raymond Baum	R	Aug-11	Attorney; Oregon Liquor Control Commission; State Legislator	503-378-6611	
Pennsylvania	James H. Cawley	D	Apr-10	Attorney; PUC Commissioner (1990-1993); Private practice	717-783-1197	jhc@state.pa.us
	Kim Pizzigrilli	R	Apr-12	Secretary of the Commonwealth; Positions at Department of State	717-772-0692	kpizzin@state.pa.us
	Tyrone Christy	D	Apr-11	Attorney; PUC Commissioner (1999-2004); Administrative Law Judge (ALJ); PUC Counsel	717-783-1763	tchristy@state.pa.us
	Robert Powelson	R	Apr-14	Attorney; PUC Commissioner (1979-1985); Private practice	717-787-4301	rpf@state.pa.us
	Wayne Gardner	D	Apr-13		717-787-1031	weg@state.pa.us
Rhode Island	Chair Ella Germani	R	Mar-13	General Counsel for Blue Cross and Blue Shield; partner of private law firm; attorney for a Rhode Island electric utility	401-941-4500 ext 100	
	Mary E. Bray	D	Mar-11	Controller, Senior Vice President in banking	401-941-4500 ext 102	
South Carolina	Chair Elizabeth B. Fleming	U	Jun-10	Chairman of the Marlboro SC, City Council; former member of Bennettsville, SC City Council	803-896-5259	Chairman.Fleming@psc.sc.gov
	David A. Wright	U	Jun-10	Former member of SC House of Representatives; public	803-896-5180	Commissioner.Wright@psc.sc.gov
	Swain Whitfield	U	Jun-12	Insurance agency owner	803-896-5180	Commissioner.Whitfield@psc.sc.gov
	Randy Mitchell	U	Jun-12	Owner and manager of a poultry farm and a rental business; Probate judge.	803-896-5259	Commissioner.Mitchell@psc.sc.gov
	John E. Howard	U	Jun-12	Printing and furniture sales	803-896-5180	ViceChairman.Howard@psc.sc.gov
	G. O'Neal Hamilton	U	Jun-12	Former member of the Spartanburg, SC City Council	803-896-5259	Commissioner.Hamilton@psc.sc.gov
	Mignon L. Clyburn	D	Jun-10	Newspaper Owner	803-896-5180	Commissioner.Clyburn@psc.sc.gov
South Dakota	Chair Dustin Johnson	R	Jan-11	Senior Policy Advisor, Governor, Truman Fellow, U.S. Department of Agriculture	605-773-3201	
	Steve Kolbeck	D	Jan-13	Held several positions within the telecommunications industry	605-773-3201	
	Gary Hanson	R	Jan-15	Real estate broker; State legislator; Utilities Commissioner of Sioux Falls; Mayor of Sioux Falls	615-741-0917	eddie.roberson@tn.gov
Tennessee	Chair Eddie Roberson Jr.	D	Jun-11	Attorney, Memphis City Court Judge; private law practice; public defender; various state government positions	615-741-3125	sara.kyle@tn.gov
	Sara Kyle	D	Jun-14	Chief of TRA Consumer Services, Div.: TRA Telecommunications Analyst	615-741-3668	mary.w.freeman@tn.gov
	Mary Freeman	D	Jun-11	Attorney, Legislative Liaison, Tennessee Supreme Court; Chief of Staff, Lt. Governor and Speaker of Senate	512-936-7025	barry.smitherman@puc.state.tx.us
Texas	Chair Barry T. Smitherman	R	Aug-13	Attorney, Assistant DA; Public Finance Investment Banker	512-936-7015	donna.nelson@puc.state.tx.us
	Donna L. Nelson	R	Aug-09	Dir. Policy for Gov. Perry, Gov.'s Liaison to PUC; Advisor to former PUC Commissioner Perlman	512-936-7005	kenneth.anderson@puc.state.tx.us
	Kenneth W. Anderson	R	Aug-11	Attorney; Solicitor General	801-530-6712	tboyer@utah.gov
Utah	Chair Ted Boyer	R	Feb-15	Accountant; Economist; Dir. of Division of Public Utilities	801-530-6492	rcampbell@utah.gov
	Richard M. Campbell	R	Feb-13	Attorney, Exec. Dir. of Utah Dept. of Commerce; Dir. of Utah Real Estate Division	801-530-6763	rallen@utah.gov
	Ron Allen	D	Feb-11	State Senator; Fire Chief; Adjunct Professor	802-828-2358	psb.clerk@state.vt.us
Vermont	Chair James Volz	U	Feb-11	Attorney; Director for Public Advocacy of the Department of Public Service	802-828-2358	psb.clerk@state.vt.us
	David Coen	U	Feb-13	Dept. store president; "business/community specialists" for the Vermont Inst. for Science, Math and Tech.	804-371-9608	psb.clerk@state.vt.us
	John D. Burke	U	Feb-15	Attorney in private practice; Adjunct Law Profe	804-371-9608	
Virginia	James C. Dimitri	U	Feb-14	Attorney, former member of the Virginia House of Delegates	804-371-9608	
	Judith Williams Jagdmann	U	Feb-12	Attorney General; SCC General Counsel	804-371-9608	
	Mark C. Christie	U	Feb-10	Attorney, Pres. State Board of Ed.; Staff former Gov. Allen	360-664-1173	
Washington	Chair Jeffrey Goltz	D	Jan-15	Attorney in private practice; Attorney for City of Seattle	360-664-1171	
	Patrick J. Oshie	D	Jan-13	Attorney, private practice; Assistant Attorney General	360-664-1169	
	Phillip Jones	R	Jan-11	International trade consultant; Legislative aide to U.S. Senator	304-340-0306	Karen.Marion
West Virginia	Chair Michael A. Albert	R	Jun-13	Chemical Engineer; Management positions at Flexsys Nitro Corp. and Monsanto	304-340-0303	Teresa.Tierno
	Edward Staats	D	Jun-09	CPA, Gov.'s Dir. of Operations	304-340-0307	Sherry.Kennedy
	Jon W. McKinney	R	Jun-11	Attorney; Business Law Division of Jackson Kelly, PLLC	608-267-7897	Sandra.Paske
Wisconsin	Chair Eric Callisto	D	Mar-15	Exec. Asst. to former commissioner; Governor's staff; Congressional staff member	608-267-7898	Alice.Heilman
	Mark Meyer	D	Mar-13	State Senate and Assembly; La Crosse, WI City Council; WI Medical Society; assistant general hotel manager	608-267-7897	Sandra.Paske
	Lauren Azar	D	Mar-13		307-777-7427	
Wyoming	Chair Alan Minier	R	Mar-15	Executive Director, Wyoming Board of Parole; Assistant Bar Counsel, Wyoming State Bar	307-777-7427	
	Steve Oxley	R	Mar-13	Division Administrator for Economic Analysis in the Wyoming Dept. of Administration and Information	307-777-7427	
	Kathleen A. Lewis	D	Mar-11	Analyst, Wyoming Legislative Service Office; Consultant, Wyoming Division of Economic Analysis	307-777-7427	

Source: SNL Financial

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We, Daniel Ford, CFA, Gregg Orrill, Theodore W. Brooks, CFA and Ross A. Fowler, hereby certify (1) that the views expressed in this research report accurately reflect our personal views about any or all of the subject securities or issuers referred to in this research report and (2) no part of our compensation was, is or will be directly or indirectly related to the specific recommendations or views expressed in this research report.

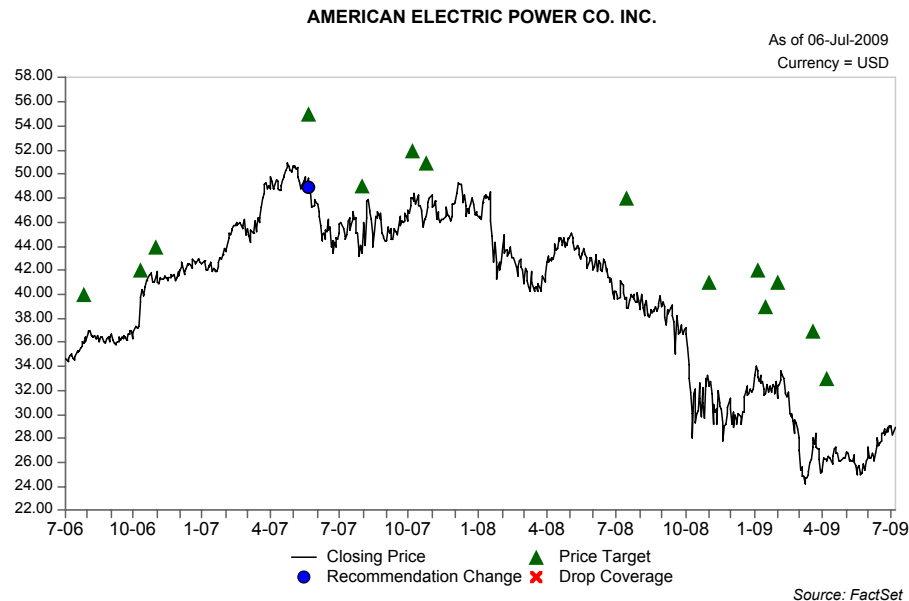
Important Disclosures:

American Electric Power (AEP)

US\$ 28.59 (09-Jul-2009)

1-Overweight / 2-Neutral

Rating and Price Target Chart:



Currency=US\$

Date	Closing Price	Rating	Price Target
06-Apr-09	26.32		33.00
19-Mar-09	28.01		37.00
30-Jan-09	31.35		41.00
15-Jan-09	31.76		39.00
05-Jan-09	33.69		42.00
03-Nov-08	32.31		41.00
15-Jul-08	39.75		48.00
24-Oct-07	46.51		51.00

Date	Closing Price	Rating	Price Target
05-Oct-07	47.97		52.00
31-Jul-07	43.49		49.00
22-May-07	48.88		55.00
22-May-07	48.88	1-Overweight	
31-Oct-06	41.43		44.00
10-Oct-06	39.31		42.00
27-Jul-06	35.88		40.00

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Barclays Capital and/or Lehman Brothers Inc. and/or one of their affiliates has received compensation for investment banking services from American Electric Power in the past 12 months.

Barclays Capital and/or an affiliate expects to receive or intends to seek compensation for investment banking services from American Electric Power within the next 3 months.

Barclays Capital and/or one of their affiliates beneficially owns 1% or more of any class of common equity securities of American Electric Power.

Barclays Capital and/or an affiliate trade regularly in the shares of American Electric Power.

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Risks Which May Impede the Achievement of the Price Target: Key risks include wholesale commodity prices, state and federal regulation, interest rates, and asset sale execution.

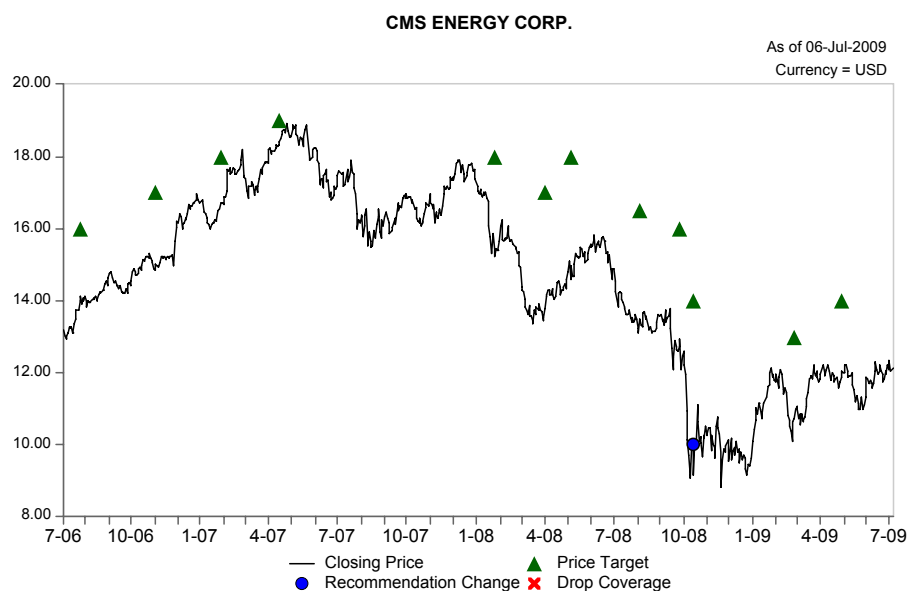
Important Disclosures Continued:

CMS Energy (CMS)

US\$ 11.81 (09-Jul-2009)

1-Overweight / 2-Neutral

Rating and Price Target Chart:



Currency=US\$

Date	Closing Price	Rating	Price Target
28-Apr-09	11.87		14.00
25-Feb-09	10.75		13.00
14-Oct-08	10.00		14.00
14-Oct-08	10.00	1-Overweight	
26-Sep-08	12.92		16.00
05-Aug-08	13.49		16.50
05-May-08	14.60		18.00

Date	Closing Price	Rating	Price Target
01-Apr-08	13.78		17.00
25-Jan-08	15.22		18.00
13-Apr-07	18.31		19.00
26-Jan-07	16.71		18.00
02-Nov-06	15.02		17.00
25-Jul-06	13.98		16.00

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Barclays Capital and/or Lehman Brothers Inc. and/or one of their affiliates has managed or co-managed within the past 12 months a 144A and/or public offering of securities for CMS Energy.

Barclays Capital and/or an affiliate makes a market or provides liquidity in the securities of CMS Energy.

Barclays Capital and/or an affiliate trade regularly in the shares of CMS Energy.

Barclays Capital and/or Lehman Brothers Inc. and/or one of their affiliates has received non-investment banking related compensation from CMS Energy within the last 12 months.

CMS Energy is or during the last 12 months has been a non-investment banking client (securities related services) of Barclays Capital and/or Lehman Brothers Inc. and/or one of their affiliates.

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Barclays Capital is associated with specialist firm Barclays Capital Market Makers who makes a market in CMS Energy stock. At any given time, the associated specialist may have "long" or "short" inventory position in the stock; and the associated specialist may be on the opposite side of orders executed on the Floor of the Exchange in the stock. Barclays Capital and/or an affiliate makes a market in the securities of this company.

Risks Which May Impede the Achievement of the Price Target: CMS Energy faces risk from Michigan utility regulation, commodity prices, and interest rates.

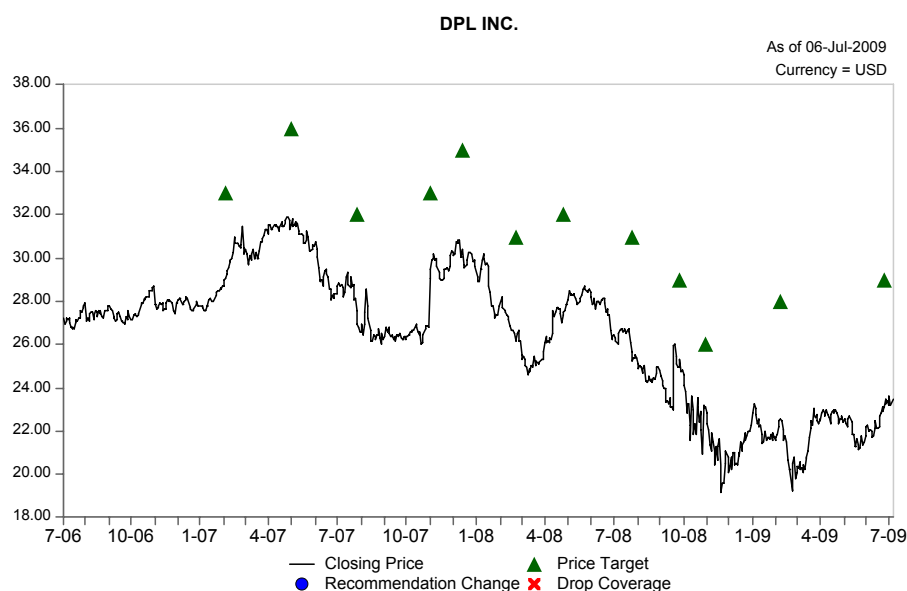
Important Disclosures Continued:

DPL Inc. (DPL)

US\$ 22.80 (09-Jul-2009)

1-Overweight / 2-Neutral

Rating and Price Target Chart:



Currency=US\$

Date	Closing Price	Rating	Price Target
24-Jun-09	23.15		29.00
06-Feb-09	22.56		28.00
30-Oct-08	23.14		26.00
26-Sep-08	25.34		29.00
24-Jul-08	25.70		31.00
24-Apr-08	27.35		32.00
22-Feb-08	26.26		31.00

Date	Closing Price	Rating	Price Target
13-Dec-07	30.41		35.00
31-Oct-07	29.04		33.00
26-Jul-07	27.61		32.00
01-May-07	31.50		36.00
02-Feb-07	29.07		33.00

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Barclays Capital and/or an affiliate makes a market or provides liquidity in the securities of DPL Inc..

Barclays Capital and/or an affiliate hold a short position of at least 1% of the outstanding share capital of DPL Inc..

Barclays Capital and/or an affiliate trade regularly in the shares of DPL Inc..

Risks Which May Impede the Achievement of the Price Target: Risks to the outlook include wholesale commodity prices, generation development market conditions, the outcome of regulatory proceedings, rating agency actions, interest rates, and access to the capital markets.

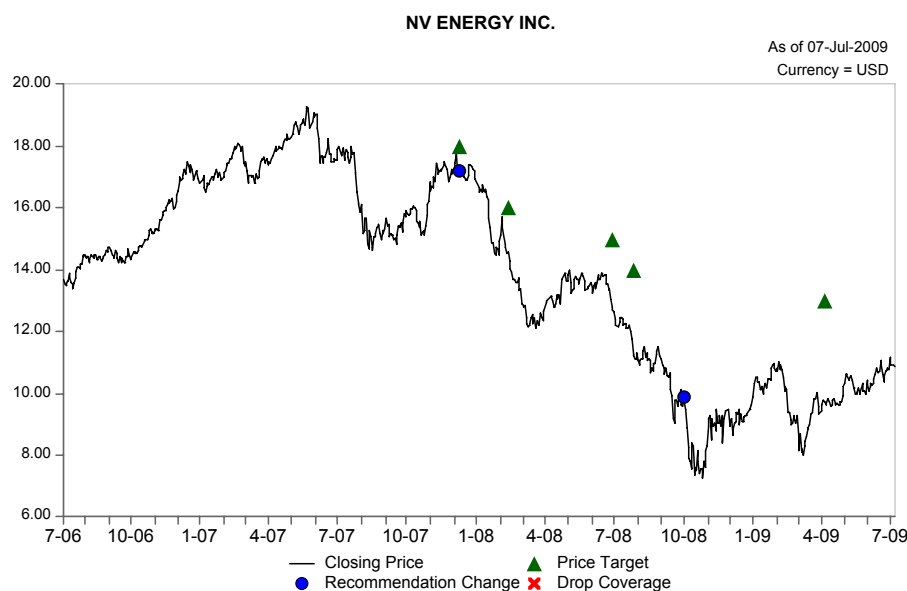
Important Disclosures Continued:

NV Energy, Inc. (NVE)

US\$ 10.66 (09-Jul-2009)

1-Overweight / 2-Neutral

Rating and Price Target Chart:



Currency=US\$

Date	Closing Price	Rating	Price Target
06-Apr-09	9.74		13.00
01-Oct-08	9.89	1-Overweight	
25-Jul-08	11.27		14.00
30-Jun-08	12.71		15.00

Date	Closing Price	Rating	Price Target
12-Feb-08	14.57		16.00
10-Dec-07	17.20		18.00
10-Dec-07	17.20	2-Equal weight	

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 Barclays Capital and/or Lehman Brothers Inc. and/or one of their affiliates has received compensation for investment banking services from NV Energy, Inc. in the past 12 months.
 Barclays Capital and/or an affiliate trade regularly in the shares of NV Energy, Inc..
 Barclays Capital and/or Lehman Brothers Inc. and/or one of their affiliates has received non-investment banking related compensation from NV Energy, Inc. within the last 12 months.
 NV Energy, Inc. is or during the past 12 months has been an investment banking client of Barclays Capital and/or Lehman Brothers Inc. and/or one of their affiliates.
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Risks Which May Impede the Achievement of the Price Target: Risks to the outlook include wholesale commodity prices, generation development market conditions, the outcome of regulatory proceedings, rating agency actions, interest rates, and access to the capital markets.

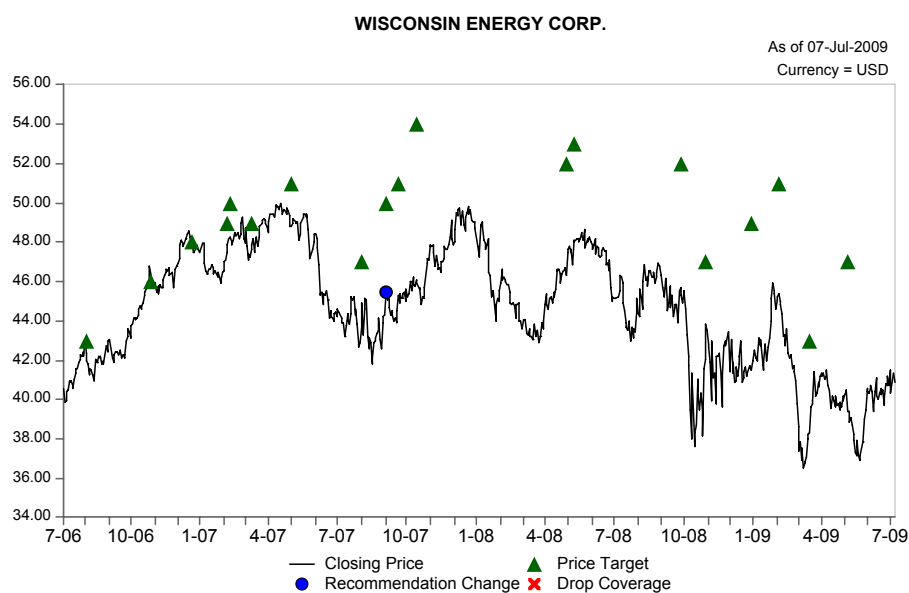
Important Disclosures Continued:

Wisconsin Energy (WEC)

US\$ 40.87 (09-Jul-2009)

1-Overweight / 2-Neutral

Rating and Price Target Chart:



Currency=US\$

Date	Closing Price	Rating	Price Target
06-May-09	39.40		47.00
17-Mar-09	38.31		43.00
04-Feb-09	45.38		51.00
30-Dec-08	41.50		49.00
30-Oct-08	43.80		47.00
29-Sep-08	45.32		52.00
08-May-08	48.08		53.00
29-Apr-08	46.31		52.00
12-Oct-07	46.11		54.00
19-Sep-07	45.33		51.00

Date	Closing Price	Rating	Price Target
04-Sep-07	45.50		50.00
04-Sep-07	45.50	1 -Overweight	
01-Aug-07	43.64		47.00
01-May-07	48.78		51.00
08-Mar-07	47.67		49.00
08-Feb-07	48.26		50.00
05-Feb-07	47.48		49.00
20-Dec-06	47.94		48.00
26-Oct-06	46.38		46.00
02-Aug-06	42.39		43.00

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Important Disclosures Continued:

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Below is the list of companies that constitute the sector coverage universe:

Alliant Energy (LNT)	American Electric Power (AEP)
CMS Energy (CMS)	Consolidated Edison (ED)
DPL Inc. (DPL)	DTE Energy (DTE)
Duke Energy (DUK)	Great Plains Energy Inc. (GXP)
Hawaiian Electric Inds (HE)	ITC Holdings (ITC)
NiSource, Inc. (NI)	Northeast Utilities (NU)
NSTAR (NST)	NV Energy, Inc. (NVE)
Peppo Holdings (POM)	PG&E Corp. (PCG)
Pinnacle West Capital (PNW)	PNM Resources (PNM)
Portland General Electric Co. (POR)	Progress Energy (PGN)
Sempra Energy (SRE)	Southern Co. (SO)
TECO Energy (TE)	Westar Energy (WR)
Wisconsin Energy (WEC)	Xcel Energy (XEL)

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São Paulo

Banco Barclays S.A. (BBSA, São Paulo)

Mentioned Company	Ticker	Price	Price Date	Stock / Sector Rating
American Electric Power	AEP	US\$ 28.59	09 Jul 2009	1-Overweight / 2-Neutral
CMS Energy	CMS	US\$ 11.81	09 Jul 2009	1-Overweight / 2-Neutral
DPL Inc.	DPL	US\$ 22.80	09 Jul 2009	1-Overweight / 2-Neutral
NV Energy, Inc.	NVE	US\$ 10.66	09 Jul 2009	1-Overweight / 2-Neutral
Wisconsin Energy	WEC	US\$ 40.87	09 Jul 2009	1-Overweight / 2-Neutral

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In addition to the stock rating, we provide sector views which rate the outlook for the sector coverage universe as 1-Positive, 2-Neutral or 3-Negative (see definitions below). A rating system using terms such as buy, hold and sell is not the equivalent of our rating system. Investors should carefully read the entire research report including the definitions of all ratings and not infer its contents from ratings alone.

Stock Ratings:

1-Overweight - The stock is expected to outperform the unweighted expected total return of the sector coverage universe over a 12-month investment horizon.

2-Equal Weight - The stock is expected to perform in line with the unweighted expected total return of the sector coverage universe over a 12-month investment horizon.

3-Underweight - The stock is expected to underperform the unweighted expected total return of the sector coverage universe over a 12-month investment horizon.

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2-Neutral - sector coverage universe fundamentals/valuations are steady, neither improving nor deteriorating.

3-Negative - sector coverage universe fundamentals/valuations are deteriorating.

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Schedule NG-SFT-R-3

Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling

GRACEFUL SYSTEMS LLC

RATE IMPACTS AND KEY DESIGN ELEMENTS OF GAS AND ELECTRIC UTILITY DECOUPLING

A COMPREHENSIVE REVIEW

Pamela G. Lesh

6/30/2009

This report catalogues all of the decoupling mechanisms in place for electric or gas utilities as of Spring 2009, and discusses several older, now expired, mechanisms as well. Where the information was obtainable, it includes the rate adjustments made under the decoupling mechanisms and expresses those as a percentage of rates. It also reviews major features of the mechanisms studied.

**RATE IMPACTS AND KEY DESIGN ELEMENTS OF GAS AND ELECTRIC
UTILITY DECOUPLING:
A COMPREHENSIVE REVIEW
Prepared by Pamela G. Lesh
June 2009**

This report compiles the rate impact experience during this decade with decoupling of retail gas and electric utility revenues from sales volumes and provides, along with this, information on relevant order numbers, statutes, mechanism descriptions, and implementing tariffs. Sources included utility and state regulatory commission websites, the American Gas Association and the Edison Electric Institute, and, in a few cases, helpful utilities. Immediately below is a brief explanation of “decoupling” as used in this report, followed by a summary of the findings and a short description of methodology. The report concludes with observations about utility ratemaking.

Decoupling

Decoupling is a regulatory term indicating that, through any one of several means, a given energy utility does not derive the portion of its revenues necessary to provide it an opportunity to recover its fixed costs of service on the basis of its sales of natural gas or electricity. Fixed costs of service include such things as the capital recovery cost of installed plant and equipment (depreciation, debt interest, and equity return), most operations and maintenance expenses and taxes. The largest cost that is not fixed is typically the cost of fuel or purchased power.

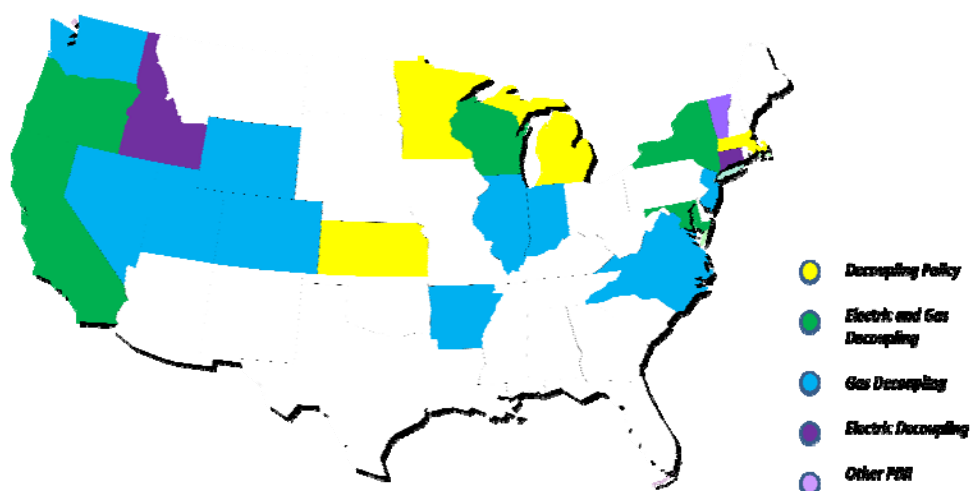
One primary means of decoupling, albeit with many variations, is through a regulatory adjustment mechanism that adjusts rates periodically to ensure that a utility records as revenue for fixed cost recovery no more and no less than the amount of revenue authorized for that cost coverage. This means of accomplishing decoupling does not affect how customers pay for energy utility services, enabling utilities to maintain volumetric rates and the incentive for customers to conserve or use energy more efficiently. In general, current rate designs include some amount of fixed customer charge per month and a per unit charge based on either gas or electricity consumption, or demand, or both. Although the utility continues to receive revenues from customers on this basis under a decoupling mechanism, it books only the revenue to cover fixed costs that its regulator has authorized, typically in a rate case or through the operation of a formula for calculating a change in fixed costs over time. For example, some such formulas change revenues authorized for fixed cost recovery according to the change in the number of customer accounts (often called revenue per customer); others change revenues for fixed cost recovery according to an inflation index, decreased for an assumed amount of productivity improvement (often called an attrition adjustment). On some regular basis, the decoupling mechanism provides a rate adjustment to ensure that customers, in effect, receive refunds or pay surcharges based on whether the revenues the utility actually received from customers were less or greater than the revenues the regulator authorized. This difference can occur for many reasons, primary among which

are weather, economic conditions, and customer behavior that differ from assumptions in the ratemaking process.

It is also possible to break the link between fixed cost recovery and electricity or natural gas consumption by changing how customers pay for energy utility services. In general, this is called “straight fixed-variable” rate design, in which the fixed monthly customer charge recovers all of the utility’s fixed costs of service and the variable, energy-related charge, covers only the variable cost of energy. Some Commissions adopting this type of rate design have called it ‘decoupling.’ While this rate design does break the link between sales and fixed cost recovery, it does so by greatly diminishing customer incentives to conserve or invest in energy efficiency. Moreover, the change in rate design from a more traditional form can significantly shift costs within and between classes of customers. In particular, those customers with lower than average consumption can experience much higher bills as costs shift from variable, usage-based, charges to fixed, billing period, charges. This decoupling report excludes examples of this rate design because it does not result in adjustments to rates as the regulatory mechanism method does.

Review Summary

A total of 28 natural gas local distribution gas utilities (LDCs) and 12 electric utilities, across 17 states, have operative decoupling mechanisms.¹ Six other states have approved decoupling in concept, through legislation or regulatory order, but specific utility mechanisms are not yet in place. The map below shows the states covered by this report:

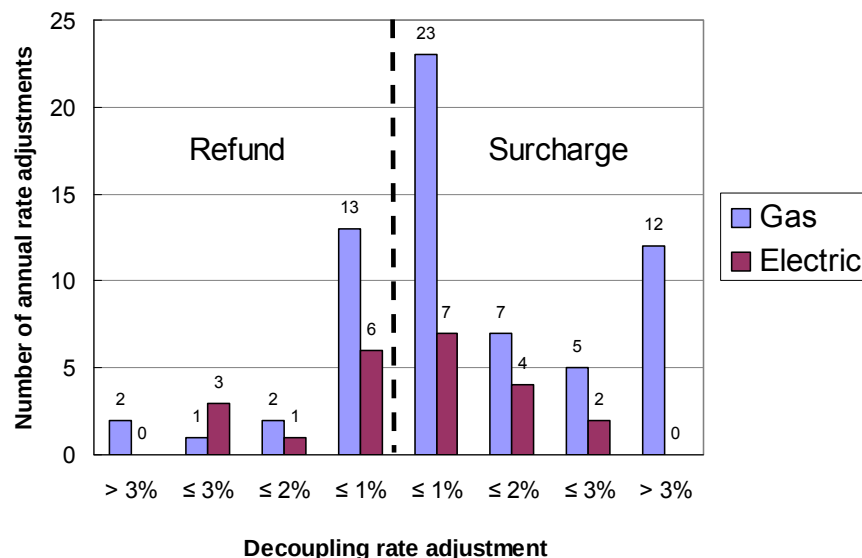


¹ This report includes two other current electric regulatory mechanisms that operate to some extent to decouple utility revenues from sales but do not permit calculation of decoupling adjustments. It also includes information on a few now-expired decoupling mechanisms, to the extent such information was discoverable.

Many of the mechanisms that exist began operation only within the last few years, although the California utilities have had some form of decoupling for much longer. Based on the available data, this review supports two definitive conclusions:

- Decoupling adjustments tend to be small, even miniscule. Compared to total residential retail rates, including gas commodity and variable electricity costs, decoupling adjustments have been most often under two percent, positive or negative, with the majority under 1 percent.² Using Energy Information Administration (EIA) data for 2007 on gas and electric consumption per customer and average rates, this amounts to less than \$1.50 per month in higher or lower charges for residential gas customers and less than \$2.00 per month in higher or lower charges for residential electric customers.
- Decoupling adjustments go both ways, providing both refunds and surcharges to customers. This is particularly true for those mechanisms that operate on a monthly basis, but also is true for those adjusted annually or semi-annually. There are many reasons, of course, that actual revenues can deviate from the revenues assumed in ratemaking. Most of the mechanisms do not adjust revenues for the effects of weather, leaving that as the primary cause of greater and lower sales volumes, particularly for residential rate schedules. Other causes include energy efficiency, programmatic and otherwise, customer conservation, price elasticity, and economic conditions. Regardless of the particular combination of causes for any given adjustment, no pattern of either rate increases or decreases emerges.

The figure below summarizes the distribution of decoupling adjustments in place since 2000.



² These are not actual rate changes, simply a comparison of the decoupling adjustment to the total rate at or near the time of the adjustment. See methodology summary for an explanation of why it is impossible to determine actual decoupling rate changes that customers may have experienced. Counts in the figure include only the annual average of those mechanisms that have monthly adjustments.

By comparison, rate adjustments under purchased gas cost adjustment or fuel/purchased power cost adjustment clauses tend to be much larger. Although a review of actual adjustments under these clauses was beyond the scope of this study, the following history for one electric (Idaho Power Company) and one gas utility (Northwest Natural Gas Company), both of which had decoupling mechanisms for part of the period, provides an example for context:

	Northwest Natural		Idaho Power	
Year	PGA % Change	Decoupling % Change ³	PCA % Change (Res)	Decoupling % Change
1995	(6.2)			
1996	(4.8)			
1997	10.5			
1998	9.2			
1999	7.2			
2000	21.4			
2001	20.8			
2002	(12.7)		7.5	
2003	4.9	0.6	(18.9)	
2004	20.1	0.36	0	
2005	16.6	0.77	0	
2006	3.8	(0.27)	(14.0)	
2007	(8.7)	(0.1)	11.0	
2008	15.6	<(1.0)	8.45	(0.8)
2009			10.2	0.8

The information gathered below supports several other observations about decoupling:

- The mechanisms have a great variety of names, almost none of which contain the word “decoupling.” Names ranged from “Billing Determinant Adjustment” to “Volume Balancing Adjustment” to “Bill Stabilization Rider” and more.
- Most mechanisms appear in a separate tariff page, although in one or two cases the mechanism is combined with an energy efficiency program tariff and the California utilities do not have a tariff for decoupling. Instead, the California utilities have regulatory authority to make the calculations and rate adjustments as part of an “Annual True-up” procedure.
- Almost all of the gas utilities with decoupling mechanisms also adjust rates to account for the effects of weather on revenues. For some, this occurs logically under the decoupling mechanism, which performs calculations based on actual, not weather-adjusted, revenues. For others, eliminating the effects of weather on the revenues the utility collects to cover fixed costs occurs under a separate tariff. Under either approach, the utilities no longer face a risk of under-recovering fixed costs or reaping a windfall if weather is different from that

³ For Northwest Natural, the decoupling adjustment is included in the overall PGA; thus, these are not additive.

assumed in the ratemaking process. In contrast, a couple of electric utilities calculate decoupling adjustments on the basis of weather-adjusted revenues. For these, the utility keeps revenues associated with sales caused by weather more extreme, and forgoes revenues lost because of weather milder, than that assumed for ratemaking purposes.

- Most of the mechanisms produce an annual adjustment, but a handful of utilities adjust rates monthly and one or two semi-annually. The monthly adjustments tend to be very small but can go up and down six times in as many months. The tables below show only the annual average of monthly adjustments and, in a few cases, high and low adjustments during the year.
- Most mechanisms perform the calculation of the difference between actual fixed cost revenues and authorized fixed costs revenues on a per customer class or per rate schedule basis, refunding or surcharging the result only to that schedule or class.
- A number of these decoupling mechanisms are in place only on a “pilot” basis, subject to cancellation or further regulatory process after 3-4 years.
- Most of the mechanisms allow utilities to keep additional revenues from growth in the number of customer accounts during a decoupling period. This can occur either by expressing the fixed costs as a revenue-per-customer amount and reconciling actual revenues to the revenue per customer amount times the current number of customers, or by adjusting the allowed revenue requirement for customer growth and reconciling actual revenues to that adjusted amount. A few utilities receive an explicit attrition adjustment, approved by the Commission and not dependent on the number of customers.
- Some of the 28 mechanisms include some unusual features. For three utilities, adjustments only occur if they are surcharges; the mechanism does not require refunds. Another two utilities can collect surcharges only if savings in gas costs offset the lost margin. Some mechanisms limit the dollar amount or percentage of rate change permitted, either deferring any excess for later recovery/credit or simply eliminating it.

The table below summarizes some of the different features of decoupling mechanisms, indicating how many of the mechanisms have each type of feature.

Feature	Gas Decoupling	Electric Decoupling
Revenue change between rate cases		
Revenue-per-customer ¹	23	4
Attrition adjustment ²	3	4
No change	3	1
No separate tariff	3	3
Timing of Rate True-ups		
Annual	19	8
Semi-annual/quarterly	2	1
Monthly	4	3
Weather ³		

Not weather-adjusted	20	10
Weather-adjusted	8	2
Limit on adjustments and/or dead-band ⁴	9	6
Per class calculation and adjustments ⁵	25	7
Earnings Test ⁶	4	
Pilot/known expiration date	11	4
Surcharges only	3	
Total Utilities Analyzed	28	12

Notes to table

1. “Revenue per customer” means that the decoupling mechanism calculates the authorized revenue to which the utility will reconcile its actual revenues by dividing the last approved fixed cost revenue requirement by the number of customer accounts assumed in that ratemaking process, and then multiplying the per-customer amount by the number of customers in the current decoupling period. For example, if the authorized fixed cost revenue requirement was \$1 billion and the ratemaking number of accounts was 1 million, the fixed cost per customer amount would be \$1000/year. If, during a given decoupling year, the actual number of customer accounts was 1,050,000, the utility would refund any amount by which its actual revenues exceeded \$1.05 billion. Thus, the additional customer accounts contribute \$50 million to fixed cost recovery.
2. “Revenue requirement true-up” means that the decoupling mechanism simply compares the actual fixed cost revenues to the amount authorized for fixed cost recovery in the utility’s last rate case, even if that was several years prior. Thus, the utility may face declining income as inflation and other factors increase fixed costs. The sub-category of these that are “with attrition” indicate the utilities for whom that authorized revenue requirement changes from year to year according some formula, generally an inflation index less an assumed amount of productivity improvement. This may be part of the decoupling mechanism, done as a means of calculating the comparator for the actual revenues collected, or external to the decoupling mechanism and causing its own rate adjustment.
3. “Weather” refers to revenue variances attributable to actual weather differing from the weather conditions assumed in the ratemaking process. If a decoupling mechanism uses actual revenues that are not weather-adjusted, that means that revenue variances attributable to weather will affect the size of the customer refund or surcharge.
4. “Limit on adjustments or a dead-band” refers to features in a given decoupling mechanism that limit the size of any (or a cumulative set of) customer refund or surcharge, or in the case of a dead-band, exclude a certain amount of the variance (again, refund or surcharge) before calculating the positive or negative decoupling rate increment. For most of the mechanisms that have a limit on the size of decoupling adjustments, any amount not refunded or surcharged carries over to the next decoupling period. That is not always the case, however.
5. “Per class calculation and spread of adjustments” means that the mechanism determines the difference between the authorized fixed cost revenue and the actual revenue on a per class or per rate schedule basis and refunds or surcharges

the resulting amount only to that rate schedule or customer class. Included in the count are utilities for which the decoupling mechanism applies only to one customer class or rate schedule. Only eight utilities have mechanisms that do not do this.

6. “Earnings test” refers to a limitation on decoupling surcharges by which the utility may not recover revenue differences calculated by the mechanism to the extent that recovery would increase its earnings over a specified return on common equity, whether the last authorized or another amount.

The next several years will significantly increase experience with decoupling, both for those utilities for whom decoupling is of relatively long-standing and for those that have just begun their implementation. It would be worthwhile to update this review at some point to determine whether these conclusions hold true with additional experience, particularly among the electric utilities for whom data is presently scarcer than for gas utilities.

Methodology

Generally, it was possible to find a tariff stating the decoupling adjustment, either in cents or dollars per therm, or cents per kWh. This was not the case only for the California utilities, whose decoupling does not occur under a separate tariff but as part of a much larger annual filing. Those utilities very helpfully provided the information needed for this report. Amounts in () are rebates to customers; other amounts are surcharges. In general, amounts are rounded to two to three digits.

It was much more difficult to find a total retail rate for the rate classes covered by the decoupling mechanism and, thus, to calculate the size of the decoupling adjustment as a percentage of the total rate. This was particularly problematic where the adjustments were for prior years or the commodity portion of the rate changed frequently, as is common for gas utilities and restructured electric utilities. In many cases, this report uses average annual (or monthly for 2009) retail gas and electric price information for the appropriate state found on the EIA website. The goal was to provide context for the decoupling adjustment, not state precise percentages and the EIA data served well for the purpose.

For a couple of reasons, it is impossible to determine from the sources available what changes in rates actually occurred when. First and foremost, whether a given decoupling adjustment caused a rate increase or decrease depends on what was in rates before for decoupling. For example, if a decoupling adjustment produced a refund one year and a somewhat smaller refund the second year, the rate change customers would experience would be a small increase, as the prior credit expired and was not fully replaced by the current credit. The reverse can also happen: the expiration of a decoupling surcharge will produce a rate decrease unless the subsequent decoupling adjustment is the same or a larger surcharge. Second, many utilities combine one or more rate changes at one time. Changes in commodity costs or balancing accounts or other tariff riders along with the decoupling adjustment are common and could easily offset or mask the decoupling adjustment. For two utilities, such offsetting was the deliberate design.

STATE/UTILITY INFORMATION

Arkansas

Arkansas Oklahoma (gas)

Case/Order No.: 07-026-U, Order No. 7 (11/20/07)

http://www.apscservices.info/efilings/docket_search_results.asp

Type of decoupling: Reconciles actual weather-adjusted revenues to rate case revenues for the residential and small business classes. No refund for over-recovery; only surcharge for under-recovery (net across all schedules). Deficiencies recovered within each class where a deficiency occurs. There is a separate weather adjustment.

Decoupling tariff: Billing Determinant Adjustment

http://www.apscservices.info/tariffs/112_gas_1.PDF

The tariff expires August 31, 2011; the utility must re-file to continue decoupling.

Energy efficiency cost recovery: incremental costs per the Energy Efficiency cost recovery tariff (adopted in Docket 07-077-TF); forecast and true-up procedure filed by April, for June adjustments.

History of Adjustments: The October 2008 filing was for no adjustment because sales were above those used in ratemaking.

Arkansas Western (gas)

Case/Order No.: 06-124-U, Order No. 6 (7/13/07)

http://www.apscservices.info/efilings/docket_search_results.asp

Type of decoupling: Reconciles actual weather-adjusted revenues to rate case revenues for the residential and small business classes only. No refund for over-recovery; only surcharge for under-recovery (net across all schedules). Deficiencies recovered within each class where a deficiency occurs. There is a separate weather adjustment.

Decoupling tariff: Billing Determinant Adjustment Tariff, Rider No. 3.6

http://www.apscservices.info/tariffs/145_gas_1.PDF

The tariff expires July 31, 2010; the utility must re-file to continue decoupling.

Energy efficiency cost recovery: Incremental costs per the Energy Efficiency cost recovery tariff (for programs approved in Docket 07-078-TF); forecast and true-up procedure; April filings for January 1 adjustment.

History of Adjustments: The October 2008 filing was for no adjustment because sales were above those used in ratemaking.

CenterPoint Energy Resources (gas)

Case/Order No.: 06-161-U; Order No. 6 (10/25/07)

http://www.apscservices.info/efilings/docket_search_results.asp

Type of decoupling: Reconciles actual weather-adjusted revenues to rate case revenues for the residential and small business classes only. No refund for over-recovery; only surcharge for under-recovery (net across all schedules). Deficiencies recovered within each class where a deficiency occurs. There is a separate weather adjustment.

Decoupling tariff: Billing Determinant Adjustment Tariff, Rider No. 6

http://www.apscservices.info/tariffs/64_gas_2.PDF

Tariff expires on December 31, 2010; the utility must re-file to continue.

Energy efficiency cost recovery: Incremental costs per the Energy Efficiency cost recovery tariff (for programs approved in Docket 07-081-TF); forecast and true-up procedure; April filings for January adjustment.

History of Adjustments: The first filing under the tariff was March 31, 2009. CenterPoint made no adjustment because sales slightly exceeded revenue requirement sales.

California

California first adopted decoupling, through the Supply Adjustment Mechanism (SAM), for gas utilities in 1978 in Decision 88835. By 1982, similar mechanisms were in place for the three electric IOUs. The ratemaking construct worked by establishing a revenue requirement for each utility annually and then reconciling actual revenues to the allowed revenues. Information on the electric decoupling adjustments during this first period is available for most years from 1983 through 1993 through an analysis done by Lawrence Berkeley Labs in 1994.⁴ The authors compared the rate adjustments that took place with those that would have occurred without the decoupling amounts. The following were the decoupling-only rate adjustments identified:

Year	PG&E (% of total rates)	SCE (% of total rates)	SDG&E ⁵ (% of total rates)
1983	2.3	Not available	1.2
1984	(3.4)	(0.5)	1.0
1985	(4.8)	(2.1)	(6.8)
1986	1.9	2.1	1.8
1987	2.1	(1.0)	11.0
1988	5.0	(1.5)	(12.0)
1989	(4.3)	2.4	0.7
1990	(5.4)	(2.1)	4.8
1991	3.9	3.5	(1.8)
1992	3.4	(0.6)	1.4
1993	0.0	(1.9)	Not available

As the gas industry restructured, gas utilities began to serve large (non-core) customers under a straight fixed-variable rate design, which continues through today. For core customers (commonly residential and smaller commercial), decoupling continued.

The CPUC largely stopped the electric decoupling mechanisms in 1996, with the advent of electric restructuring. It is unclear whether the last reconciliation adjustment was 1995

⁴ The Theory and Practice of Decoupling, Joseph Eto et al., Lawrence Berkeley Laboratory, January 1994
Website: <http://eetd.lbl.gov/EA/emp/reports/34555.pdf>

⁵ The article providing these historical decoupling adjustments does not explain the outlying double-digit increase and decrease for SDG&E. Given that the two are in consecutive years, one might surmise that a load forecasting or mathematical error caused the decoupling increase in the one year only to correct it and reverse the amount in the following year.

or 1996. In 2001, however, the Legislature passed Public Utilities Code section 739.10, which required that the CPUC resume decoupling.

739.10. The commission shall ensure that errors in estimates of demand elasticity or sales do not result in material over or under-collections of the electrical corporations.

In individual rate cases following this, the CPUC approved resumption of electric.⁶

Pacific Gas and Electric (electric)

Case/Order Nos.: A.02-11-017 et al.

http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/37086.htm

The first adjustment under the various mechanisms occurred at the end of 2004 to be effective during 2005.

Type of decoupling: Reconciles actual, non-weather-adjusted revenues to approved revenue requirement. An attrition adjustment increases revenue requirement in non-rate case years. PG&E has three specific accounts that combine to accomplish decoupling: the Distribution Revenue Adjustment Mechanism, the Nuclear Decommissioning Revenue Adjustment Mechanism, and the Utility Generation Balancing Account.

Decoupling tariff: No specific tariff.

Filing Schedule: Adjustments occur through the Annual Electric True-Up filing.

Energy efficiency cost recovery: Yes

History of Adjustments

Year of Adjustment ⁷	Revenue Rqmt (\$ millions)	Decoupling Adjustment (\$ millions)	Decoupling as % of Total Revenue ⁸
2005	9,715	99.41	1.0
2006	9,875	24.64	0.25
2007	10,371	148.9	1.4
2008	10,609	11.4	0.11
2009	11,169	103.55	0.9

Pacific Gas and Electric (gas)

Case/Order Nos.: A.02-11-017 et al.

http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/37086.htm

The first adjustment under the various mechanisms occurred at the end of 2004 to be effective during 2005.

Type of decoupling: Reconciles actual, non-weather-adjusted revenues to approved revenue requirement. An attrition adjustment increases revenue requirement in non-rate case years.

Decoupling tariff: No specific tariff; adjustment occurs in Annual True-Up filing

Filing Schedule: Filings occur in December for January 1 effective dates

Energy efficiency cost recovery: Yes

⁶ Some amount of decoupling, for some of the utilities, may have occurred between adoption of restructuring and the adoption of section 739.10. It is unclear.

⁷ The adjustment is collected in the year following the year that the revenue variance occurred.

⁸ Because the decoupling adjustments occur along with other adjustments, it is not possible to determine specific adjustments (dollars or percentages) by rate schedule. It is possible to identify the total decoupling adjustment as a percentage of total revenues for the year to which the adjustment relates.

History of Adjustments

Year of Adjustment	Revenue Rqmt (\$ millions)	Decoupling Adjustment (\$ millions)	Decoupling as a % of Delivery Revenue ⁹
2006	982.8	37.95	3.9
2007	1,026	46.77	4.6
2008	1,095	11.26	1
2009	1,091	50.86	4.7

Southern California Edison (electric)

Case/Order Nos.: A.93-120-29; Decision 02-04-055. The first adjustment under the various mechanisms occurred at the end of 2004 to be effective during 2005.

Type of decoupling: Reconciles actual, non-weather-adjusted revenues to approved revenue requirement. An attrition adjustment increases revenue requirement in non-rate case years.

Decoupling tariff: No specific tariff.

Filing Schedule: Adjustments occur through the Annual Electric True-Up filing.

Energy efficiency cost recovery: Yes

History of Adjustments

Year	Annual Change in Rates for Decoupling ¹⁰ (%)
2004	(2.1)
2005	(2.1)
2006	0.1
2007	(1.0)
2008	2.2

San Diego Gas & Electric (electric)

Case/Order No.: Case/Order No.: A.02-12-027

http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/44820.htm

Type of decoupling: Reconciles actual, non-weather-adjusted revenues to approved revenue requirement. An attrition adjustment increases revenue requirement in non-rate case years.

Decoupling tariff: No separate tariff

⁹ The percentages would be much smaller with commodity reflected in the total as well. Because PG&E could not provide the per-therm adjustment related to decoupling, it was not possible to calculate the decoupling as a percentage of the total rate to customers, even using EIA data.

¹⁰ Rate changes reflect the difference between the rate change without the base revenue requirement balancing account (BRRBA) and the rate change with the BRRBA. Because the decoupling adjustments occur along with other adjustments, it is not possible to determine specific adjustments (dollars or percentages) by rate schedule. It is possible to identify the total decoupling adjustment as a percentage of total revenues for the year to which the adjustment relates.

Filing Schedule: Adjustments occur in annual filings that combine many adjustments, including both revenue and cost reconciliations.

Energy efficiency cost recovery: Yes

History of Adjustments¹¹

Year	Rate (¢/kWh)	Decoupling Rate Change (¢/kWh)	Decoupling change compared to Rate (%)
2005	13.773	(0.055)	(0.40)
2006	13.935	(0.210)	(1.5)
2007	13.997	(0.051)	(0.36)
2008	13.606	(0.044)	0.32
2009	16.726	0.128	0.76

SoCal Gas/SDG&E (gas)

Case/Order No.: A.02-12-027; D.05-03-023

http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/44820.htm

Type of decoupling: Reconciles actual, non-weather-adjusted revenues to approved revenue requirement. An attrition adjustment increases revenue requirement in non-rate case years.

Decoupling tariff: No separate tariff

Filing Schedule: Adjustments occur in annual filings that combine many adjustments, including both revenue and cost reconciliations

Energy efficiency cost recovery: Yes

History of Adjustments¹²

Year/ Core/Non-Core	Rate (¢/therm)	Decoupling Rate Change (¢/therm)	Decoupling Change compared to Rate (%)
2006			
Core	48.348	0.012	0.02
Non-Core	5.36	0	0
2007			
Core	50.196	0.024	0.05
Non-Core	4.852	(0.001)	(0.01)
2008			
Core	51.526	0.001	0
Non-Core	3.576	(0.001)	(0.04)
2009			
Core	55.052	0.003	0.01
Non-Core	2.954	0.002	0.07

¹¹ The numbers are estimates only and reflect the best efforts of SDG&E to isolate the decoupling elements. Contact Lisa Davidson at 858-636-3928 for information or updates.

¹² The numbers below are estimates only and reflect the company's best efforts to isolate the decoupling elements. Rates shown are for delivery services only.

Southwest Gas Corporation (gas)

Case/Order No.: A.02-02-012, Order 04-03-034

http://docs.cpuc.ca.gov/Published/Final_decision/35920.htm

Type of decoupling: Reconciles actual, non-weather-adjusted revenues to approved revenue requirement. An attrition adjustment increases revenue requirement in non-rate case years.

Decoupling tariff: Core Fixed Cost Adjustment Mechanism (line item in cost of gas)
<http://www.swgas.com/tariffs/catariff/rates/historic/2009/06-07-2009/rates-nocal.pdf> and
http://www.swgas.com/tariffs/catariff/cover/ca_gas_tariff.pdf (see Sheet 6739-G)

Filing Schedule: Changes occur every January 1

Energy efficiency cost recovery: Yes

History of Adjustments

Year	Average Commercial Rate ¹³ (\$/therm)	Northern Territory Decoupling Adj (\$/therm)	% of Retail Rate (est ¹⁴)	Southern Territory Decoupling Adj (\$/therm)	% of Retail Rate ¹⁵
2005	1.07	0.004	0.4	0.05	4.7
2006	1.04	0	0	0.05	4.8
2007	1.02	(0.0006)	<(.01)	0.004	0.4
2008	1.17	(0.016)	(1.4)	0.010	0.9
2009	0.94	(0.051)	(5)	0.013	1.4

Colorado

Colorado has adopted decoupling only for one utility – gas – and then only for a three-year experiment. Recent legislation authorizes the Commission to ensure cost recovery for both electric and natural gas energy efficiency programs but does not address decoupling. See §40-3.2-103 and 104.

Public Service of Colorado (gas)

Case/Order No.: 06S-656G; Order No. C07-0568

<http://www.dora.state.co.us/puc/DocketsDecisions/HighprofileDockets/06S-656G.htm>

¹³ Source: EIA data, annual through 2008 and January 2009. For simplicity, this assumes translates MCF into therms without the small additional amount of btu associated with a therm.

¹⁴ This is an estimate only, using EIA average California commercial retail prices for each of the years above. Although the core class includes both residential and commercial, the percentage estimate uses the lower commercial number to be conservative regarding the size of the adjustment as a percentage of customer rates.

¹⁵ This is an estimate only, using EIA average California commercial retail prices for each of the years above. Although the core class includes both residential and commercial, the percentage estimate uses the lower commercial number to be conservative regarding the size of the adjustment as a percentage of customer rates.

Type of decoupling: Reconciliation of residential use-per-customer times ratemaking margin to actual, weather-normalized use-per-customer times ratemaking margin; utility allowed to recover only differences greater than or equal to 1.3% decline in use per customer (cumulates every year of mechanism); increases in use-per-customer accrue to offset losses in use-per-customer in prior or future years.

Decoupling Tariff: Partial Decoupling Rate Adjustment, Sheet 51

http://www.xcelenergy.com/SiteCollectionDocuments/docs/psco_gas_entire_tariff.pdf

The tariff expires October 1, 2011; the utility must re-file to continue decoupling. Filing

Schedule: Adjusts every year on October 1

Energy efficiency cost recovery: Cost recovery reconciled to actual costs; semi-annual filing for July 1 and January 1 rate changes

History of adjustments

September 2008 filing for margin differences July 2007 through June 2008: \$0

Connecticut

2007 Connecticut legislation requires that the Commission adopt decoupling mechanisms for the states' electric and natural gas utilities. CT Public Act No. 07-242

<http://www.cga.ct.gov/2007/ACT/PA/2007PA-00242-R00HB-07432-PA.htm>

United Illuminating (electric)

Case/Order No.: 08-07-04 (February 2009 and June 2009)

<http://www.dpuc.state.ct.us/FINALDEC.NSF/0d1e102026cb64d98525644800691cfe/f4217b3542e2b08b852575530075d08c?OpenDocument> and

<http://www.dpuc.state.ct.us/FINALDEC.NSF/2b40c6ef76b67c438525644800692943/3b76f3e31c22cb19852575cb005cea73?OpenDocument>

Type of decoupling: Reconciliation of actual, non-weather adjusted revenues to ratemaking revenues. Refunds or surcharges allocated to all classes based on revenue.

Decoupling Tariff: United Illuminating has not yet filed a tariff to implement the Commission's approval of its decoupling mechanism because it was awaiting the results of a request for reconsideration. A tariff will likely be filed shortly. Extension beyond 2010 requires specific Commission approval.

Filing Schedule: Within 14 months after new rates effective

Energy efficiency cost recovery: Yes

History of Adjustments

There will not be any adjustments under this order for approximately 14 months.

Idaho

Idaho Power Company (electric)

Case/Order No.: IPC-E-04-15; Order No. 30267

<http://www.puc.idaho.gov/search/search.htm> (Search under order number).

Type of decoupling: For residential and small commercial customers, the mechanism reconciles actual number of customers to ratemaking number of customers times a set fixed cost per customer and weather-adjusted sales per customer to ratemaking sales per customer for a set fixed cost per kWh amount. Adjustments are capped at 3% over the

previous year, with carry-over to subsequent years. Although the mechanism specifies calculating and refunding/charging any adjustment on a per class basis, the Commission departed from this in the first two adjustments because of concern regarding the lack of current cost of service studies to support the underlying cost allocations. This is a three-year pilot program, expiring May 31, 2010.

Decoupling tariff: Schedule 54

<http://www.puc.state.id.us/tariff/approved/Electric/Idaho%20Power%20Company.pdf>

Filing Schedule: Adjustments occur each June 1 (filed March 15), with adjustments based on results from the prior calendar year.

Energy efficiency cost recovery: Incremental costs per the Energy Efficiency cost recovery tariff (adopted in Docket 07-077-TF); forecast and reconciliation procedure filed by April for June adjustments.

History of Adjustments

Year	Residential Decoupling (\$ million)	Adjustment ¹⁶ (¢/kWh)	Rate change (%)	Small Commercial Decoupling (\$ million)	Adjustment (¢/kWh)	Rate change (%)
2008	(3.6)	(0.0457)	(0.71) ¹⁷	1.2	(0.0457)	(0.71)
2009 ¹⁸	1.3	0.0529	0.82	1.4	0.0529	0.82

Kansas

In 2008, the Commission issued an order addressing generally cost recovery and incentives associated with utility energy efficiency programs. Docket No. 08-GIMX-441-GIV (November 14, 2008)

<http://www.kcc.state.ks.us/scan/200811/20081114142730.pdf>. The Commission endorsed the concept of using a tariff rider to recover program costs on a timely basis, with pre-filing of programs and budgets to provide utilities assurance of concurrence in their plans. In the order, the Commission also determined that decoupling was the best method of addressing the throughput incentive that utilities otherwise face, rejecting both a straight fixed-variable rate design and lost revenue recovery as reasonable alternatives. It invited utilities to file decoupling proposals in connection with their energy efficiency programs.

Illinois

North Shore Gas (gas)

¹⁶ The Commission ordered that the decoupling adjustments be summed and the result designed into an even adjustment across the two customer classes. This was, in part, because Idaho Power lacked a recent cost of service study suitable to allocate fixed costs between the two classes.

¹⁷ This is an estimate using the 2009 retail rate implied by the filing of the 2009 adjustment and the 2008 adjustment.

¹⁸ Filed March 15, but not yet approved.

Case/Order No.: 07-0241/07-0242 (Cons)

<http://www.icc.illinois.gov/docket/files.aspx?no=07-0241&docId=119858>

Type of decoupling: Reconciles actual, non-weather-adjusted margin revenue per customer to ratemaking margin per customer, on a per-class basis.

Decoupling tariff: Volume Balancing Adjustment (VBA), sheets 60-64

<http://www.northshoregasdelivery.com/news/tariffs/vba.pdf>

This is a four-year pilot only; to continue, the utility must make a general rate filing in which the Commission extends the program.

Filing Schedule: Monthly adjustments began March 2008. The utility will make a reconciliation filing every February. The first filing was in February 2009 for the ten months of 2008 included in the mechanism.

Energy efficiency cost recovery: Rider Energy Efficiency Program (EEP); program period runs July 1 to June 30 each year.

History of adjustments¹⁹

North Shore Gas Service Classification	True-up: rate case to actual margin (\$)	True-up: percentage of margin (%)	True-up: percentage of total revenues (%)²⁰
Residential Sales	(547,804.42)	(3.3)	(0.46)
Residential Transportation	(5,101.34)	(1.3)	(0.1)
Comm/Ind Sales	(89,053.00)	(3)	(0.33)
Comm/Ind Transportation	(327,781.95)	(0.5)	(0.5)

Peoples Gas and Coke (gas)

Case/Order No.: 07-0241/07-0242 (Cons)

<http://www.icc.illinois.gov/docket/files.aspx?no=07-0241&docId=119858>

Type of decoupling: Reconciles actual, non-weather-adjusted margin revenue per customer to ratemaking margin per customer, on a per class basis.

Decoupling tariff: Volume Balancing Adjustment (VBA), Sheets 61-65

<http://www.peoplesgasdelivery.com/news/tariffs/vba.pdf>

This is a four-year pilot only; to continue, the utility must make a general rate filing in which the Commission extends the program.

Filing Schedule: Monthly adjustments began March 2008. The utility will make a reconciliation filing every February. The first filing was in February 2009 for the ten months of 2008 included in the mechanism.

Energy efficiency cost recovery: Rider Energy Efficiency Program (EEP); program period runs July 1 to June 30 each year.

History of adjustments²¹

¹⁹ Prepared from the annual reconciliation filing.

²⁰ Commodity rates change frequently. The percentage was estimated using average city gate gas cost for Illinois per EIA data, annual 2008, \$8.48/Mcf.

²¹ Prepared from the annual reconciliation filing.

Peoples Gas Service Classification	True-up: rate case to actual margin (\$)	True-up: percentage of margin (%)	True-up: percentage of total revenues (est.)²² (%)
Residential Sales	(2,035,714.64)	(2)	(0.43)
Residential Transportation	(53,882.01)	(2.4)	(0.15)
Comm/Ind Sales	(431,457.89)	(1)	(0.19)
Comm/Ind Transportation	(2,217,245.22)	(6.9)	(0.73)

Indiana

Vectren Indiana Gas (gas)

Case/Order No.: 42943 (December 2006)

https://myweb.in.gov/IURC/eds/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b631800befe7

Type of decoupling: Reconciles actual, non-weather-adjusted margin revenues per customer to ratemaking margin revenues per customer, with an adjustment for customer additions and reductions; only 85% of amount (positive or negative) included in rates; earnings capped at allowed return on common equity, with earnings shortfalls from prior periods allowed to offset potential returns to customers. The mechanism operates on a per class basis. The utility also has a separate weather adjustment tariff that applies only during the seven winter months.

Decoupling tariff: Appendix I, Energy Efficiency Rider, Sheet 38

https://www.vectrenenergy.com/cms/assets/pdfs/indiana_gas_tariff.pdf

Energy efficiency cost recovery: Yes, in the same tariff

History of adjustments

Rate Schedule/Year	Decoupling Adjustment (\$/therm)	Adjustment as a % of Margin	Adjustment as a % of Total Rate
2008			
Residential (210)	0.017	6.4	1.5
General (220/225)	0.0034	2.0	0.3
2009			
Residential (210)	0.00364	1.4	0.4
General (220/225)	(0.00762)	4.4	(0.86)

Vectren Southern Indiana Gas (gas)

²² Commodity rates change frequently. The percentage was estimated using average city gate gas cost for Illinois per EIA data, annual 2008, \$8.48/Mcf.

Case/Order No.: 42943 (December 2006)

https://myweb.in.gov/IURC/eds/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b631800befe7

Type of decoupling: Reconciles actual, non-weather-adjusted margin revenues per customer to ratemaking margin revenues per customer, with an adjustment for customer additions and reductions; only 85% of amount (positive or negative) included in rates; earnings capped at allowed return on common equity, with earnings shortfalls from prior periods allowed to offset potential returns to customers. The mechanism operates on a per class basis. The utility also has a separate weather adjustment tariff that applies only during the seven winter months.

Decoupling tariff: Appendix I, Energy Efficiency Rider, Sheet 38

https://www.vectrenenergy.com/cms/assets/pdfs/south_services_gas_tariff.pdf

Energy efficiency cost recovery: Yes, in the same tariff

History of adjustments

Rate Schedule/Year	Decoupling Adjustment (\$/therm)	Adjustment as a % of Margin	Adjustment as a % of Total Rate
2008			
Residential (110)	0.0085	4.7	0.8
General (120/125)	0.0035	2.9	0.3
2009			
Residential (110)	0.00152	0.8	0.2
General (120/125)	(0.00469)	(4)	(0.6)

Citizen's Gas & Coke (gas)

Case/Order No.: 42767 (April 2007)

https://myweb.in.gov/IURC/eds/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b631800dd673

Type of decoupling: Reconciles actual, non-weather-adjusted margin revenues per customer to ratemaking margin revenues per customer, with an adjustment for customer additions and reductions. The mechanism operates on a per class basis. The utility also has a separate weather adjustment tariff that applies only during the seven winter months.

Decoupling tariff: Rider E, page 505

<http://www.citizensgas.com/pdf/NGRatesRidersTC/RiderE.pdf>

Energy efficiency cost recovery: Yes, through Rider E

History of adjustments

Rate Schedule/Year	Decoupling Adjustment (\$/therm)	Adjustment as a % of Margin	Adjustment as a % of Total Rate
2008			
Res Non-Heat	0.002	0.45	0.16
Res Heat	(0.0002)	(0.067)	(0.02)
General Non-Heat	(0.0006)	(0.5)	(0.006)
General Heat	0	0	0

2009			
Res Non-Heat	0.0133	3	1.2
Res Heat	0.0223	7.3	2.2
General Non-Heat	0.0157	12.86	1.9
General Heat	0.0212	12.9	2.4

Maryland

Maryland has both gas and electric decoupling in place; the former began in the early 2000s, and the latter just within the last few years. All of the mechanisms make monthly adjustments. The amounts below are averages of the monthly adjustments for the periods shown. For several of the utilities, the largest and smallest adjustments within a given year are also shown.

Baltimore Gas & Electric (electric)

Case/Order No.: [Unable to locate]

Type of Decoupling: Reconciles actual, non-weather-adjusted revenue to ratemaking revenue, adjusted for net customers added, on distribution only, by rate schedule. Maximum change in rates per month is 10%, with any adjustment amount in excess of that carried over to future periods.

Decoupling Tariff: Monthly Rate Adjustment, Rider 25

<http://www.bge.com/portal/site/bge/menuitem.b0ab2663e7ca6787047eb471016176a0/>

Filing Schedule: Monthly

Energy efficiency cost recovery: Yes

History of Adjustments

Period	Res. Dec. Adj (¢/kWh)	Dec. Adj % of Retail Rate ²³	Small Comm. Dec. Adj (¢/kWh)	Dec. Adj % of Retail Rate	Gen'l Comm. Dec. Adj (¢/kWh)	Dec. Adj % of Retail Rate
2008 ²⁴						
Largest Adj	0.445		0.215		0.2303	
Smallest Adj	(0.066)		(0.215)		0.1456	
Average Adj	0.136	1.1	0.025	0.22	0.21	2.1
2009						
Largest Adj	0.237		0.119		0.23	
Smallest Adj	(0.237)		(0.215)		(0.215)	
Average Adj	(0.069)	(0.5)	(0.048)	(0.4)	(0.043)	(0.4)

Delmarva (electric)

²³ EIA data on Maryland retail rates for the respective years used as a proxy to determine percentages.

²⁴ The mechanism was effective January 2008, with the first adjustment occurring in March 2008 based on January variances. The filing for the November 2008 adjustment was missing from the Maryland Commission website.

Case/Order No.: Case Jacket 9093; Order 81518, July 2007

http://webapp.psc.state.md.us/Intranet/Casenum/CaseAction_new.cfm?RequestTimeout=500

Type of decoupling: Reconciles actual, non-weather-adjusted revenue to ratemaking revenue, adjusted for net customers added, on distribution only, by rate schedule. Maximum change in rates per month is 10%, with any adjustment amount in excess of that carried over to future periods. Adjusts monthly.

Decoupling Tariff: Bill Stabilization Adjustment Rider, Leaf 102

<http://www.delmarva.com/home/choice/md/tariffs/>

Energy efficiency cost recovery: Yes, Demand-Side Management Surcharge Rider, Leaf 132

History of adjustments

Period/Rate	Average Decoupling Adjustment ²⁵ (¢/kWh)	Estimated Total Rate ²⁶ (¢/kWh)	Decoupling as % of Rate ²⁷
11/07 – 10/08			
Residential	0.16	11.09	1.4
General	0.21	11.80	1.8
11/08 – 4/09			
Residential	0.16	10.69	1.5
General	0.29	11.40	2.5

PEPCO (electric)

Case/Order No.: Case Jacket 9092, Order 81517, July 2007

http://webapp.psc.state.md.us/Intranet/Casenum/CaseAction_new.cfm?RequestTimeout=500

Type of decoupling: Reconciles actual, non-weather-adjusted revenue to ratemaking revenue, adjusted for net customers added, on distribution only, by rate schedule. Maximum change in rates per month is 10%, with any adjustment amount in excess of that carried over to future periods. Adjusts monthly.

Decoupling tariff: Bill Stabilization Adjustment Rider, page 47

http://www.pepco.com/res/documents/md_tariff.pdf

Energy efficiency cost recovery: Yes, Demand-Side Management Surcharge Rider, page 48

History of Adjustments

²⁵ PEPCO makes a monthly adjustment. The numbers shown are the average across the periods identified. For the year 11/07 to 10/08, there were 14 downward adjustments across the three classes and 22 upward adjustments. For the partial period 11/08 to 2/09, there were 2 downward adjustments and 10 upward.

²⁶ For residential, this is the average (summer/winter) standard offer rate for the decoupling periods. For general, the rate is estimated from the price to compare on PEPCO's website. For large industrial, the rate is from EIA 2006 price data for Maryland.

²⁷ The percentage shown is only as of total rate for residential and general service. The percentage is of delivery costs only for large industrial; with added commodity, the percentage change would be much lower.

Period/Rate	Average Decoupling Adjustment ²⁸ (¢/kWh)	Estimated Total Rate ²⁹ (¢/kWh)	Decoupling as % of Rate
11/07 – 10/08			
Residential	0.06	10.75	0.56
General	0.08	12.74	0.63
Large	0.013	8.14	0.16
11/08 – 2/09			
Residential	0.25	10.75	2.3
General	0.14	12.74	1.1
Large	0.02	8.14	0.25

Baltimore Gas & Electric (gas)

Case/Order No.: Case 9036; Order 80460

http://webapp.psc.state.md.us/Intranet/Casenum/submit_new.cfm?DirPath=C:\Casenum\9000-9099\9036\Item_116\&CaseN=9036\Item_116

Type of decoupling: Reconciles actual, non-weather-adjusted revenue to ratemaking revenue, adjusted for net customers added, on distribution only, by rate schedule.

Maximum change in rates per month is 10%, with any adjustment amount in excess of that carried over to future periods. Adjusts monthly.

Decoupling tariff: Monthly Rate Adjustment, Rider 8

<http://www.bge.com/portal/site/bge/menuitem.d7305449a99570c7047eb471016176a0/>

Energy efficiency cost recovery: Yes. Gas Efficiency Charge, Rider 1

History of Adjustments

Period	Residential Decoupling Adjustment (\$/therm)	Decoupling Adjustment % of Retail Rate ³⁰	Commercial Decoupling Adjustment (\$/therm)	Decoupling Adjustment % of Retail Rate
2006 ³¹				
Largest Adj	0.05		0.05	
Smallest Adj	(0.01)		(0.05)	
Average Adj	0.0316	1.9	(0.005)	(0.4)
2007 ³²				

²⁸ PEPCO makes a monthly adjustment. The numbers shown are the average across the periods identified. For the year 11/07 to 10/08, there were 14 downward adjustments across the three classes and 22 upward adjustments. For the partial period 11/08 to 2/09, there were 2 downward adjustments and 10 upward.

²⁹ For residential, this is the average (summer/winter) standard offer rate for the decoupling periods. For general, the rate is estimated from the price to compare on PEPCO's website. For large industrial, the rate is from EIA 2006 price data for Maryland. It is not clear if the standard offer rate is with or without distribution charges built in. This analysis assumes these are included. If they are not, the decoupling adjustment as a percentage of the total rate would be even lower.

³⁰ EIA data for the respective years used as a proxy for the retail rate.

³¹ The first decoupling adjustment appears to have occurred in July 2006. The filing for the 09/06 adjustment was missing from the Maryland Commission website.

Largest Adj	0.0397		0.0159	
Smallest Adj	(0.05)		(0.05)	
Average Adj	(0.0323)	(2.1)	(0.043)	(3.5)
2008 ³³				
Largest Adj	0.073		0.05	
Smallest Adj	(0.05)		(0.05)	
Average Adj	0.02	1.2	(0.0223)	(1.7)
2009				
Largest Adj	0.008		0.0212	
Smallest Adj	(0.0272)		(0.05)	
Average Adj	(0.014)	<(0.1)	(0.01)	(0.8)

Washington Gas Light (gas)

Case/Order No.: Case 8990; Order No. 80130

http://webapp.psc.state.md.us/Intranet/Casenum/CaseAction_new.cfm?RequestTimeout=500

Type of decoupling: Reconciles actual, non-weather-adjusted revenue to ratemaking revenue, adjusted for net customers added, on distribution only, by rate schedule. Maximum change in rates per month is 5¢, with any adjustment amount in excess of that carried over to future periods. Adjusts monthly.

Decoupling tariff: Revenue Normalization Adjustment, General Service Provisions No. 30 <http://www.washgas.com/FileUpload/File/Tariffs/MD/md9899.pdf>

Energy efficiency cost recovery: Yes. Demand-side Management Surcharge Adjustment, General Service Provisions No. 22

History of Adjustments:

Period	Residential Decoupling \$/therm	Decoupling Adjustment % of Retail ³⁴	Commercial Decoupling \$/therm	Decoupling Adjustment % of Retail
December 2005	0.0258	1.7	0.0139	1.2
2006				
Largest Adj	0.05		0.045	
Smallest Adj	0.0146		(0.05)	
Average Adj	0.0415	2.5	(0.02)	(1.5)
2007				
Largest Adj	0.0323		0.0499	
Smallest Adj	(0.05)		(0.05)	
Average Adj	(0.0085)	(0.56)	(0.027)	(2.2)
2008				
Largest Adj	0.05		0.05	
Smallest Adj	(0.05)		(0.05)	

³² Filings for adjustments for January, March and April were missing from the Maryland Commission website.

³³ Filings for adjustments in April, October and November were missing from the Maryland Commission website.

³⁴ Retail prices based on EIA data for Maryland for respective years.

Average Adj 2009 ³⁵	(0.0013)	(0.08)	(0.005)	(0.39)
Largest Adj	0.0344		0.0245	
Smallest Adj	(0.05)		(0.0386)	
Average Adj	(0.018)	(1.5)	(0.022)	(2.0)

Massachusetts

Massachusetts has announced a regulatory policy in favor of decoupling for all of its gas and electric utilities. D.P.U 07-50-A (July 2008)

<http://www.mass.gov/Eoeea/docs/dpu/electric/07-50/71608dpuord.pdf>. None of the utilities have mechanisms in place yet.

Minnesota

In 2007, the Minnesota legislature enacted Section 216B.2412, <https://www.revisor.leg.state.mn.us/statutes/?id=216B.2412> in which it defined an alternative approach to utility regulation, *decoupling*, and directed the Public Utilities Commission to “establish criteria and standards” by which it could adopt decoupling for the state’s rate-regulated utilities. In addition, the legislation authorized the PUC to allow one or more utilities “to participate in a pilot program to assess the merits of a rate-decoupling strategy to promote energy efficiency and conservation,” subject to the criteria and standards that the PUC will have established. To date, no utility pilots are in place.

Michigan

In 2008, Michigan passed PA 295, <http://legislature.mi.gov/doc.aspx?2007-SB-0213> a comprehensive bill adopting a renewable energy portfolio standard and an energy efficiency portfolio standard for state electric and natural gas utilities. Section 89(6) states that the commission shall authorize any natural gas utility that spends a minimum of 0.5% of total natural gas retail sales revenues, including natural gas commodity costs, in a year on commission-approved energy efficiency programs to implement a symmetrical revenue decoupling true-up mechanism that adjusts for sales volumes that are above or below the projected levels that were used to determine the authorized revenue requirement. The Commission has not yet approved a decoupling mechanism under this section.

Nevada

In 2008, the Nevada Public Service Commission adopted temporary rules allowing gas utilities to propose a decoupling mechanism in a general rate case filed within one year of the approval of a set of energy efficiency programs for that utility. Docket No. 07-06046. <http://pucweb1.state.nv.us/wx/DocView.aspx?DataSource=PUCN+Imaging&ParamEnc=>

³⁵ Through May 2009.

[28%3a4D605690F11E27F012E1E60C8921FD1EEDD79CFEA0229DFE8B7EB14452AF2C471C7CEAA1CF970B67CDA2AD4AE0CDFC51ED5922B5E6DD1B98989E303FB8F15D5D6D08D6153BAE4347AB1F5BA1161334F5CABA7968A9E94DA44ABC5B285CF46983F6774787FD62A42DC2948DCD8AA319003AF71485E3D7CE47887E97027141DC1825216D42A37388884DCB825AF30A075ADD824901B04B3682834A110EC55B357C08408C4D4732131396D0FDA84963BDD583915C2B541AC56C896E054A5B867D68DE185F5C7EA0D65E1F97F262BB32E527A71B4540EC51FFAA201E818A3E9D5315](http://pucweb1.state.nv.us/PUCN/general/pucnac.aspx) The rules specify revenue per customer mechanism design, with adjustments done on a per class basis. NAC (Nevada Administrative Code) 704.953.
<http://pucweb1.state.nv.us/PUCN/general/pucnac.aspx>

New Jersey

South Jersey Gas Company (gas)

Case/Order No.: Order No. GR05121019 (October 2006) (Link not available)

Type of decoupling: Reconciles ratemaking margin revenue per customer with actual, non-weather adjusted margin per customer, adjusted for net customers added, on a per rate schedule basis. Any revenue deficiency related to non-weather (calculated pursuant to a separate schedule – Rider D) causes is limited to the amount of offsetting revenue from sales of surplus gas. Surcharges recoveries may not occur if the utility would earn more than its allowed return on common equity but amounts excluded carry over.

Decoupling tariff: Conservation Incentive Program, Rider M, Sheet 97c

<http://www.southjerseygas.com/108/tariff/Tariff060109.pdf>

Energy efficiency cost recovery: Yes. Rider K, Clean Energy Program Clause (CLEP)

Note that this includes lost revenue associated with programmatic savings.

History of Adjustments³⁶

Class/Year	Decoupling Adjustment ³⁷ (\$/therm)	Decoupling amount as % of margin ³⁸	Decoupling amount as % of rate ³⁹
2008			
Residential	0.0443	9.8	2.8
General	0.0392	10.9	2.6
General Large Volume	(0.0037)	(1.3)	(0.3)
2009			
Residential	0.0707	15.6	4.8
General	0.0684	19	5
General Large Volume	0.0062	2.1	0.5

³⁶ The mechanism began in October 2006, with the first adjustment in October 2007.

³⁷ South Jersey does not make rate changes for the decoupling adjustments because its tariff requires that it offset the amounts against revenues it earns from the release of gas supplies.

³⁸ Margin based on currently published tariffs.

³⁹ This is an estimate using the EIA natural gas city gate price for 2008 and January 2009, respectively.

These amounts are not rate changes per se. In particular, the 2009 decoupling adjustments as a percentage of the total rate is shown without regard to the prior 2008 rate change. On a cumulative basis, the increase was only approximately 1.6% for residential customers.

New Jersey Natural Gas Company (gas)

Case/Order No.: Order No. GR05121020 (October 2006) (link not available)

Type of decoupling: Reconciles ratemaking margin revenues per customer with actual, non-weather adjusted margin per customer, adjusted for net customers added, on a per rate schedule basis. Any revenue deficiency attributable to non-weather (calculated pursuant to a separate schedule – Rider D) causes is limited to the amount of offsetting revenue from sales of surplus gas. Surcharges recoveries may not occur if the utility would earn more than its allowed return on common equity but any recovery so excluded carries over.

Decoupling tariff: Conservation Incentive Program, Rider I

<http://www.njng.com/regulatory/pdf/060109.pdf>

Energy efficiency cost recovery: Yes. Rider E, Clean Energy Program Clause (CLEP)

History of Adjustments⁴⁰

Class/Year	Decoupling Adjustment⁴¹ (\$/therm)	Decoupling amount as % of rate⁴²
2008		
Residential	0.0261	1.7
General	0.0248	2.0
2009		
Residential	0.0378	2.5
General	0.0424	2.8

New York

Consolidated Edison (gas)

Case/Order No.: 06-G-1332; 1-102-06G1332 (September 2007)

<http://documents.dps.state.ny.us/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=06-G-1332&submit=Search+for+Case%2FMatter+Number>

Type of decoupling: Reconciles actual, non-weather-adjusted revenues per customer with ratemaking revenues per customer, according to several service classification groupings.

Decoupling tariff: General Information Special Adjustment No. 14, leaf 181-182;

apparently in force only 10/07 through 9/08

[http://www.coned.com/documents/gas_tariff/pdf/0003\(09\)-General_Information.pdf#page=12](http://www.coned.com/documents/gas_tariff/pdf/0003(09)-General_Information.pdf#page=12)

Energy efficiency cost recovery: Yes

History of Adjustments (Unable to locate)

⁴⁰ The mechanism began in October 2006, with the first adjustment in October 2007.

⁴¹ New Jersey Natural Gas does not make rate changes for the decoupling adjustments because its tariff requires that it offset the amounts against revenues it earns from the release of gas supplies.

⁴² This is an estimate using the EIA natural gas city gate price for 2008 and January 2009, respectively. These amounts are not rate changes per se. 2008 EIA commercial retail gas price data for New Jersey was not available; this uses the 2007 annual.

Consolidated Edison (electric)

Case/Order No.: 07-E-0523; 1-301-07E0523 (March 25, 2008)⁴³

<http://documents.dps.state.ny.us/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=07-E-0523&submit=Search+for+Case%2FMatter+Number>

Type of decoupling: Reconciles actual, non-weather adjusted revenues to ratemaking revenues on a per class basis. Adjusts semi-annually.

Decoupling tariff: PSC No. 9-Electricity, Leaf 168F

<http://www.coned.com/documents/elec/165-168i.pdf>

Energy efficiency cost recovery: Pending; decoupling specifically adopted without connection to an approved energy efficiency program

History of Adjustments⁴⁴

Service Class	Adjustment	Percent of Delivery Charge ⁴⁵
Residential (1)	(0.1502)	(2.3)
General Commercial (2)	(0.0071)	(0.8)

National Fuel Gas Distribution (gas)

Case/Order No.: 07-G-0141, 1-102-07G0141 (December 2007)

<http://documents.dps.state.ny.us/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=07-G-0141&submit=Search+for+Case%2FMatter+Number>

Type of decoupling: Reconciles actual, weather-normalized margin revenue per customer with ratemaking margin per customer, adjusted for net customers added. There is a separate weather adjustment that applies for October through May only.

Decoupling tariff: Conservation Incentive Program Cost Recovery, Sheet 148.9; adjustments effective on annual basis, December through November

<https://www2.dps.state.ny.us/ETS/jobs/display/download/4677590.pdf>

Energy efficiency cost recovery: Yes

History of Adjustments

Service Class	Adjustment \$/Mcf	Percent of Rates ⁴⁶
Residential	(0.082)	(0.77)
General Service	(0.082)	(0.87)

⁴³ The order included a 10 basis point ROE reduction ordered to account for the effect of the decoupling mechanism on the utility's risk.

⁴⁴ The decoupling mechanism applies to 10 schedules in total. Many of those contain demand charges that make calculation of the per kWh decoupling adjustment as a percentage of the rate difficult. The two shown above contain by far the greatest number of customers.

⁴⁵ This charge does not include electricity commodity. The decoupling adjustments as a percentage of that amount would be even smaller.

⁴⁶ Based on May 2009 retail rates. These rates change monthly.

Orange & Rockland (electric)

Case/Order No.: 07-E-0949; Order No. 1-302-07E0949

<http://documents.dps.state.ny.us/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=07-E-0949&submit=Search+for+Case%2FMatter+Number>

Type of decoupling: Reconciles actual, non-weather adjusted revenues with ratemaking revenues (delivery only) per class with certain schedules excluded: economic development, lighting, special contracts. Ratemaking revenues adjust automatically according to a three-year schedule. Program ends June 30, 2011.

Decoupling tariff: General Information Sheet 25

<http://www.oru.com/documents/tariffsandregulatorydocuments/ny/electrictariff/electricG125.pdf> ;

Energy efficiency cost recovery: Programs and recovery pending in separate proceeding 07-M-0548 to be decided later in 2008.

History of Adjustments: None to date.

North Carolina

In 2007, North Carolina enacted a statute specifically authorizing the Commission to approve decoupling mechanisms for natural gas utilities.

http://www.ncleg.net/EnactedLegislation/Statutes/HTML/BySection/Chapter_62/GS_62-133.7.html

Piedmont Natural Gas (gas)

Case/Order No.: Dockets G-9, Sub 499 (November 2005) and G-9, Sub 550 (November 2008) <http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=KAAAAA52350B&parm3=000123283> and <http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=SAAAAAA89280B&parm3=000128268>

Type of decoupling: Reconciles actual, non-weather adjusted margin per customer with ratemaking margin per customer, by rate schedule. Adjusts twice a year.

Decoupling tariff: Customer Utilization Tracker (CUT), now called Margin Decoupling Tracker, Appendix C

<http://www.piedmontng.com/rates/tariffs/uploadedTariffs/ncTariff.pdf>

Energy efficiency cost recovery: In the initial 3-year decoupling experiment, the utility donated funds totaling \$750,000 for energy efficiency without recovery; in the extension, the Commission approved including \$1.275 million in rates for these programs

Energy efficiency incentives: No.

History of Adjustments

Period	Residential Adjustment \$/therm	% of Rate ⁴⁷	Small Comm. Adjustment \$/therm	% of Rate	Med. Comm. Adjustment \$/therm	% of Rate
Apr 2006	0.02262	1.3	0.0123	0.87	0.000860	<0.1
Nov 2006	0.05181	3.1	0.02339	1.7	0.011389	1.0
Apr 2007	0.07791	5.0	0.04127	3.2	0.00996	1.0
Nov 2007	0.06153	3.9	0.03118	2.4	0.01213	1.2
Apr 2008	0.08471	5.1	0.04732	3.3	0.01452	1.2
Nov 2008	0.07494	4.5	0.03819	2.7	0.02394	1.9

Public Service Company of North Carolina (gas)

Case/Order No.: G-5, Sub 495 (October 2008) <http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=RAAAA89280B&parm3=000128260>

Type of decoupling: Reconciles actual, non-weather adjusted margin per customer with ratemaking margin per customer, by rate schedule. Adjusts twice a year.

Decoupling tariff: Rider C Customer Usage Tracker

http://www.psnenergy.com/NR/rdonlyres/0E0B99DA-911C-4674-AF7E-EA5602091DB6/0/Rider_C.pdf

Energy efficiency cost recovery: Yes, up to \$750,000 per year, with no true-up to actual expenditures

History of Adjustments

The Commission just approved the decoupling mechanism for PS Co of North Carolina in October 2008. The first adjustment under the mechanism has not occurred as of May 2009, but will likely appear shortly.

Oregon

Cascade Natural Gas (gas)

Case/Order No.: UG 167; Order No. 06-191

<http://apps.puc.state.or.us/orders/2006ords/06-191.pdf>

Type of decoupling: Reconciles actual margin per customer with ratemaking margin per customer, adjusted for current customer count but does so separately for weather-related variances and all other variances. Calculations and rate adjustments done on a per rate schedule basis. Earnings sharing applies to extent earnings with adjustment clauses recoveries exceed 175 basis points over allowed return on common equity. Decoupling ends after three years unless the utility re-files.

Decoupling tariff: Rule 19, Original Sheet 30, Conservation Alliance Plan mechanism

http://www.cngc.com/post/rates_tariffs/oregon/0030_Rule_19_-_Conservation_Alliance_Plan.pdf

⁴⁷ EIA annual city gate prices for respective years used as a proxy for total rate. It is useful to remember these are not necessarily rate changes in customer bills. Assuming nothing else was occurring, slight rate increases would have occurred in April and November 2006 and April 2007, but then a decrease in November 2007 as the decoupling adjustment declined from the prior level, an increase in April 2008 and an decrease again in November 2008.

Energy efficiency cost recovery: Yes, through a public purpose charge the revenue from which goes to the Energy Trust of Oregon for programs

History of Adjustments

	Decoupling Use-Per- Customer Forecast Change (\$/therm)	Decoupling True-Up (\$/therm)	Average Total Rate (\$/therm)	Total Decoupling as % of Rate
7/06 – 6/07				
Residential	0.01693	0.01538	1.26	2.6
Commercial	0.00934	0.01538	1.12	2.2
7/07 – 6/08				
Residential	(0.0292)	(0.02055)	1.39	(3.6)
Commercial	(0.0112)	(0.02055)	1.25	(2.5)

Northwest Natural Gas (gas)

Case/Order No.: UG 163, Order No. 07-426

<http://apps.puc.state.or.us/orders/2007ords/07-426.pdf>

Type of decoupling: Reconciles actual, weather-adjusted margin per customer with ratemaking margin per customer, adjusted for current customer count, by customer class. Weather-adjustment occurs through a separate tariff from which customers can choose to opt out. Program runs through October 2012.

Decoupling tariff: Schedule 190

[https://www.nwnatural.com/CMS300/uploadedFiles/24190ai\(3\).pdf](https://www.nwnatural.com/CMS300/uploadedFiles/24190ai(3).pdf)

Energy efficiency cost recovery: Through a public purpose charge – the revenues collected go to the Energy Trust of Oregon to run programs.

History of Adjustments

Year	Decoupling Adjustment (\$ million)	Decoupling Adjustment (% of rate)
2003	3.6	0.6
2004	2.1	0.36
2005	6.2	0.77
2006	(2.2)	(0.27)
2007	0.8	<0.1
2008	(2.5)	<(1.0)

PacifiCorp (electric)

Case/Order No.: UE-94; Order No. 98-191 (not available electronically)

<http://apps.puc.state.or.us/edockets/docket.asp?DocketID=5178>

Type of decoupling: Reconciled actual weather-adjusted revenues to ratemaking revenues for distribution services only. Ratemaking revenues increased each year, automatically, by inflation less a 0.3% productivity factor. The mechanism was part of a 3-year

alternate-form-of-regulation (AFOR). The AFOR expired shortly before Oregon restructuring (February 2002).

Decoupling tariff: NA

Energy efficiency cost recovery: Yes, through a public purpose charge included in the package.

History of Adjustments⁴⁸

Customer Class	1999	2000	2001
Residential	(0.39)	1.9	1.85
Small General Service	(0.6)	(0.22)	0.06
General Service	(0.83)	(0.31)	0.09
Large General Service	0.61	0.33	(0.3)
Irrigation	0.45	0.25	(0.2)

Portland General Electric (electric)

Case/Order No.: UE-197; Order No. 09-020 and 09-196

<http://apps.puc.state.or.us/orders/2009ords/09-176.pdf>

Type of decoupling: Reconciles actual, weather-adjusted fixed cost revenue per customer for residential and small general service to ratemaking fixed cost revenue per customer, by customer class. Decoupling adjustments limited to two percent per year, positive or negative; amounts in excess do not roll over to future periods.⁴⁹ Program runs two years.

Decoupling tariff: Schedule 123

http://www.portlandgeneral.com/about_pge/regulatory_affairs/pdfs/schedules/Sched_123.pdf

Energy efficiency cost recovery: Yes, through a regular and an add-on public purpose charge; virtually all of the funding goes to the Energy Trust of Oregon to run programs.

History of Adjustments: None yet. The first should occur in 2010.

Utah

Questar Gas (gas)

Case/Order No.: 05-057-T01 (October 2006)

<http://www.psc.utah.gov/utilities/gas/06orders/Oct/05057t01oass.pdf>

Type of decoupling: Reconciles actual, non-weather adjusted margin revenues per customer with ratemaking margin revenues per customer, only for the general service class. Accruals to the balancing account per year capped at a cumulative 1% of gross revenues per twelve-month period. Three-year program ends December 2009. Renewal dockets are pending.

Decoupling tariff: 2.08 Conservation Enabling Tariff

<http://www.questargas.com/Tariffs/uttariff.pdf>

Energy efficiency cost recovery: Yes, 2.09 Demand-side Management tariff

History of Adjustments

⁴⁸ The figures shown are actual rate changes (in %) attributable to decoupling within the overall alternate form of regulation.

⁴⁹ Commission order approving decoupling applied a 10 basis point return on common equity reduction.

Period	Decoupling Adjustment (% of overall rate)
7/06 – 3/07	0.27
4/07 – 8/07	0.36
9/07 – 3/08	(0.47)
4/08 – 8/08	0.01

Vermont

Central Vermont Public Service (electric)

Case/Order No.: 7336, <http://www.state.vt.us/psb/orders/2008/files/7336%20Final.pdf>

Type of decoupling: CVPS has an alternative regulatory plan under which it may adjust rates every year based on forecast costs and sales. This limits any benefit of increased sales during a given year to a partial year, at best. In addition, there is an adjustment mechanism for earnings that fall outside of a dead-band of 75 basis points around the allowed return on common equity. Outside of the dead-band, any excess or shortfall is first shared between the utility and customers and, beyond a certain amount, passed through in full to customers. If consumption reductions have caused revenues to fall, this mechanism may trigger a partial collection of the shortfall from customers. It will be difficult to calculate to what extent revenue changes driven by consumption changes have contributed to any adjustment, however.

Decoupling tariff: NA

Energy efficiency cost recovery: Public Purpose Charge with funds sent to Efficiency Vermont, a non-profit third-party provider

History of Adjustments: It will not be possible to isolate the effects of sales changes from other elements included in the plan.

Green Mountain Power (electric)

Case/Order No.: 7175 and 7176 <http://www.state.vt.us/psb/orders/2006/files/7175-7176finalorder.pdf>

Type of decoupling: As with Central Vermont Public Service (CVPS), the partial decoupling occurs through a comprehensive alternative form of regulation. Under the 3-year plan, GMP changes its rates every year based on a forecast of sales and costs. Thus, sales increases provide, at most, a partial year benefit to the Company. In addition, the earnings sharing provision operates, as CVPS' does, to minimize the loss if sales should fall significantly from forecast as well as share the benefit with customers if sales should rise. The Board explicitly found that full decoupling was unnecessary with this comprehensive plan.

Decoupling tariff: NA

Energy efficiency cost recovery: Public Purpose Charge with funds sent to Efficiency Vermont, a non-profit third-party provider

History of Adjustments: It will not be possible to isolate the effects of sales changes from other elements included in the plan.

Virginia

Virginia Gas (gas)

Case/Order No.: PUE-2008-00060 (December 2008)

<http://docket.scc.virginia.gov/vaprod/main.asp>

Type of decoupling: For residential customers only, reconciles actual, weather-adjusted revenue per customer to ratemaking revenue per customer approved in an existing performance-based ratemaking plan. A separate weather adjustment rider exists.

Decoupling tariff: Revenue Normalization Adjustment Rider D (not available in utility's on-line tariff)

Energy efficiency cost recovery: Yes

History of Adjustments: None to date.

Washington

Cascade Natural Gas (gas)

Case/Order No.: UG-060256 (January 2007), Order Nos. 05, 06, and 07

<http://wutc.wa.gov/rms2.nsf/177d98baa5918c7388256a550064a61e/c6d08ccab87aceb2882572610082a4df!OpenDocument> ,

<http://wutc.wa.gov/rms2.nsf/177d98baa5918c7388256a550064a61e/2293364b330b249c8825733900798c2c!OpenDocument>,

<http://wutc.wa.gov/rms2.nsf/177d98baa5918c7388256a550064a61e/67316d49ff5b839e882573670080db42!OpenDocument>

Type of decoupling: Reconciles actual, weather-adjusted margin revenue per customer with ratemaking margin revenue per customer, for residential and general commercial service only, by rate schedule. Adjustments occur the annual Temporary Technical Adjustment filing.

Decoupling tariff: Original Sheet 25, Conservation Alliance Plan mechanism

http://www.engc.com/post/rates_tariffs/washington/021_Rule_Conservation_Alliance_Plan_Mechanism.pdf

Energy efficiency cost recovery: Yes

History of Adjustments: The mechanism took effect October 2007 and the first adjustment period ran through December 2008. Cascade reported an adjustment of (\$401,328.82) in March 2009. The minor rate decrease associated with this will occur along with Cascade's PGA filing in Fall 2009.

Avista (gas)

Case/Order No.: UG-060518 (February 2007)

<http://wutc.wa.gov/rms2.nsf/177d98baa5918c7388256a550064a61e/flf6a64cb9d2aa0688257275007a230d!OpenDocument>

Type of decoupling: Reconciles actual, weather-adjusted margin revenue per customer with ratemaking margin revenue per customer, for general service customers only, with a positive or negative adjustment of 90% of the difference. Recoveries limited to amounts that bring the utility up to its allowed return on common equity and contingent upon meeting certain energy efficiency targets, using a sliding scale. Any surcharges resulting

from the decoupling calculation limited to two percent per year, cumulative over the program (6%). Three-year pilot program.

Decoupling tariff: Schedule 159 (applies only to General Service)

http://www.avistautilities.com/services/energypricing/tariffs/wa/gas/Documents/WA_159.pdf

Energy efficiency cost recovery: Yes, schedule 191

History of Adjustments

Period	Adjustment Effective in Rates ¢/therm	Percentage of Margin	Percentage of Total Rate ⁵⁰
1/07 – 6/07	.257	1.25	0.28
7/07 – 12/07	.257	1.18	0.25
1/08 – 6/08	.593	2.73	0.58
7/08 – 12/08	.593	2.73	0.56

Wisconsin

Wisconsin Public Service Corporation (electric and gas)

Case/Order No.: Docket No. 6690-UR-119

http://psc.wi.gov/apps/erf_share/view/viewdoc.aspx?docid=106184 and

http://psc.wi.gov/apps/erf_share/view/viewdoc.aspx?docid=108565

Type of Decoupling: For both gas and electric, reconciles actual, non-weather-adjusted margin revenues per customer, by customer class, with ratemaking margin revenues per customer, adjusted for actual number of customers. Margin determined several different ways, depending on customer class and whether distribution fixed costs or supply fixed cost. Caps apply – amounts in excess of the cap not booked for later credit or surcharge; caps based on revenue requirement value of 100 basis points of return on common equity (\$8 for gas; \$14 for electric). Four-year pilot program.

Decoupling Tariffs: PSCW-8, Schedule GRSM-1 (gas)

<http://www.wisconsinpublicservice.com/news/gas/GRSM.pdf>: PSCW-7, Schedule

ERSM-1 (electric) <http://www.wisconsinpublicservice.com/news/electric/ERSM.pdf> ling

Weather: Revenues not weather adjusted – actual revenues used

Energy efficiency cost recovery: Yes

History of Adjustments: None to date.

Wyoming

Questar Gas Company (gas)

Case/Order No.: 30010-94-GR-8 (May 2009)⁵¹ (order not yet available electronically)

⁵⁰ Estimated using 2007, 2008 and January 2009 City Gate gas prices for Washington from EIA. These are not actual rate changes; rather just the adjustment expressed as a percentage of the entire rate. During the period of Avista's decoupling adjustment so far, there have been only two rate changes.

⁵¹ The order is not yet available on the Commission's website.

Type of decoupling: Reportedly similar to Utah mechanism, which reconciles actual, non-weather adjusted margin revenues per customer with ratemaking margin revenues per customer, only for one class of customer.

Decoupling tariff: (tariff not yet available electronically)

Energy efficiency cost recovery: Yes

Closing Observation

Finding all of the decoupling mechanisms and summarizing the adjustments made under them was an exceedingly difficult task. I have a total of over 25 years in utility matters, most spent in the regulatory affairs department of a mid-sized electric utility. I know my way around a tariff and am generally familiar with naming conventions and so forth used by public utility commissions. Despite this wealth of experience, the task was difficult. This caused me to wonder what those not on the “inside” can possibly think of how utilities and regulators present information? Most would not think that the obfuscation was deliberate but many would conclude that ensuring people actually understood utility rates and regulation was not the goal.

The means of tackling this issue range from the simple to the significant. As a simple matter, some conventions around what utilities and commissions call things, what information appears in filing letters and annual (perhaps) information compiling tariffs and riders into complete rate information would help. This would seem a useful place for NARUC to work, in collaboration with the AGA and EEI. A far more significant effort would be the re-thinking of the tariff structure used by virtually every utility in the country. I suspect that most have changed little, in structure, for well over 50 years. General conditions appear in one place, riders and adjustments clauses in another, “base” rates somewhere else in schedule numbers that mean nothing to anyone. Tariffs may now be “on” the Internet, but they are not Internet-enabled or Internet-friendly. It seems likely that the future holds more variation in, and personalization of, rates, not less. Again, the utilities and regulators should collaborate to envision the “tariffs” (if we still call them that) of the future and how the industry might go about the transformation.

PRE-FILED REBUTTAL TESTIMONY

OF

PAUL R. MOUL

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1 **I. INTRODUCTION AND SCOPE OF REBUTTAL TESTIMONY**

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

3 A. My name is Paul R. Moul and I am Managing Consultant at the firm P. Moul &
4 Associates. My business address is 251 Hopkins Road, Haddonfield, NJ 08033-3062.

6 **Q. Mr. Moul, have you previously submitted direct testimony in this proceeding?**

7 A. Yes. My direct testimony was submitted to the Rhode Island Public Utilities
8 Commission (the “Commission”) with the Company’s initial filing on June 1, 2009.

10 **Q. What is the purpose of your testimony?**

11 A. I am providing rebuttal testimony on behalf of The Narragansett Electric Company d/b/a
12 National Grid (“the Company”) regarding the testimony presented by Mr. Matthew I.
13 Kahal, a witness appearing on behalf of the Rhode Island Division of Public Utilities and
14 Carriers (the “Division”).

16 **II. REBUTTAL SUMMARY**

17 **Q. Will you identify the areas of controversy concerning the cost of capital issue in this**
18 **proceeding?**

19 A. The central areas of dispute concerning the cost of capital in this case involve: (i) the
20 appropriate capital structure ratios that should be used to calculate the weighted average
21 cost of capital for the Company, (ii) whether the cost of equity proposed by Mr. Kahal, if
22 adopted, will be adequate to provide the Company with the opportunity to earn its cost of

1 capital during the rate effective period, (iii) the determination of a reasonable Discounted
2 Cash Flow cost rate, (iv) whether other methods provide a reasonable measure of the
3 Company's cost of equity and (v) whether an adjustment to the cost of capital
4 determination is necessary because of the Company's decoupling proposal.
5

6 **Q. Please summarize your rebuttal testimony.**

7 A. In my opinion, the overall rate of return proposed by Mr. Kahal is inadequate because he
8 has determined it by using (i) capital structure ratios that are too heavily weighted with
9 debt, and (ii) a 10.1 percent rate of return on common equity, which is below the returns
10 required by investors for an electric utility, such as the Company, and does not
11 adequately reflect the higher risk of common equity due to a volatile stock market..
12

13 **Q. Why is it important that the Commission provide the Company with a rate of return**
14 **that meets investors' requirements?**

15 A. The return on equity utilized by the Commission to set rates embodies in a single
16 numerical value a clear signal of regulatory support for the utilities that it regulates.
17 Although cost allocations, rate design issues, and regulatory policies relative to the cost
18 of service are important considerations, the opportunity to achieve a reasonable return on
19 equity represents a direct signal to the investment community of regulatory support. In a
20 single figure, the authorized return on equity provides a common and widely understood
21 benchmark that can be compared from one company to another and is the basis by which
22 returns on all financial assets (stocks – both utility and non-regulated, bonds, money

1 market instruments, and so forth) can be measured. So, while varying degrees of
2 sophistication are required to interpret the meaning of specific Commission policies on
3 technical matters such as the test period, rate design issues, and cost of service items, the
4 return on equity figure is universally understood and communicates to investors the types
5 of returns that they can reasonably expect from an investment in utilities operating in
6 Rhode Island. To obtain new capital and retain existing capital, the rate of return on
7 common equity must be high enough to satisfy investors. I believe that the rate of return
8 on common equity proposed by Mr. Kahal is inadequate to provide the Company with the
9 opportunity to earn its cost of capital during the rate effective period. The rebuttal
10 testimony of Ms. Julie Cannell also addresses this issue.

11
12 **Q. Mr. Kahal observes that his proposed rate of return on common equity is lower**
13 **than the return established in the settlements for the Company in 2000 and 2004.**
14 **Please respond.**

15 A. In today's market environment, a reduction in the Company's return would send a
16 negative signal of regulatory support to the investment community. Moreover, the table
17 of returns presented by Mr. Kahal on page 9 of his testimony is is not probative of the
18 issues to be decided in this case. For most (i.e., 6 out of 9 references) of the returns noted
19 therein, the authorized returns were the result of settlements. Further, the returns listed
20 by Mr. Kahal cover a seven-year period during which market conditions varied widely,
21 and in many instances were different than today. For these reasons, there is no basis to

1 reduce the Company's cost of equity in this case based upon the returns listed by Mr.
2 Kahal.

3
4 **Q. What items have you identified that indicate that return on equity proposed by Mr.**
5 **Kahal is too low?**

6 A. For a variety of technical reasons that I will cover later in my rebuttal testimony, the rate
7 of return testimony submitted by Mr. Kahal contains various misspecifications in the
8 models used to measure the cost of equity. In general, the infirmities in his testimony
9 include:

- 10 • A DCF return that understates investor expectations.
- 11 • A failure to adjust the market determined cost rate in order to properly apply it to the
12 Company's book value capitalization.
- 13 • A failure to employ the Risk Premium method to measure the Company's cost of
14 equity.
- 15 • CAPM results that fail to adequately reflect investor requirements in the context of
16 the total return expected on the stock market generally.

17
18 **III. CAPITAL STRUCTURE RATIOS**

19 **Q. Before proceeding with your discussion of the cost of equity, have you reviewed the**
20 **capital structure ratios that have been proposed by Mr. Kahal?**

21 A. Yes. It is my opinion that Mr. Kahal has proposed capital structure ratios that are over
22 weighted with debt and as a consequence contain less equity than is appropriate. Mr.

1 Kahal's testimony seems to indicate that I provided insufficient support for the
2 Company's proposed capital structure ratios. On this point, I strenuously disagree.
3 Rather, I provided a comprehensive analysis of the Company's proposed capital structure
4 ratios and fully supported the reasonableness of those ratios.
5

6 **Q. Will you recap the Company's capital structure proposal in this case?**

7 A. Yes. As a preliminary matter, the numerical values contained in the Company's initial
8 filing associated with the restructuring of its capital structure are merely place-holders
9 until the proposed debt financing is completed. Once approved by the Commission, the
10 Company will undertake the planned debt financing, utilize the net proceeds to repay
11 short-term debt and make dividend payments, and then substitute the actual capital
12 structure ratios for the ratios originally submitted in the rate case. It is expected that the
13 actual ratios that will result from the transaction will be very close to the ratios submitted
14 by the Company in its initial filing in this case.
15

16 **Q. Mr. Kahal questions the need for a 50% common equity ratio for the Company and**
17 **points to his proxy groups as justification for proposing a lower ratio. Please**
18 **respond.**

19 A. Mr. Kahal provides common equity ratios for his two proxy groups of 55.4% for his gas
20 group and 47.5% for his electric group as shown on pages 1 and 2 of Schedule MIK-3.
21 Mr. Kahal then states that since these ratios do not include short-term debt, he calculates
22 average common equity ratios of 47.4% for his gas group and 44.8% for his electric

1 group by including short-term debt. But, he does not show how he arrives at those
2 figures. Regardless of how these figures were arrived at there are problems with these
3 comparisons.

4
5 As to the gas group, there are difficulties with such comparisons due to the seasonal
6 short-term borrowing for the gas companies. Gas companies typically borrow short-term
7 to finance natural gas purchased and stored in inventory preceding the heating season.
8 Short-term borrowings begin to accumulate in the late spring/early summer and continue
9 to increase until the heating season begins in the fall. Natural gas is then withdrawn from
10 storage, sold to customers, and short-term debt is the repaid. Then the cycle repeats.
11 Working capital needs are also seasonal whereby as accounts receivable increase during
12 the peak heating months, short-term debt increases and then is repaid as accounts
13 receivable are converted into cash. Due to the seasonality of short-term borrowings by
14 gas companies, spot amounts, such as end of quarter balances, are not used to measure
15 typical levels of short-term debt, but rather an average is normally employed, such as a
16 twelve month average. As a consequence, the comparison of common equity ratios to the
17 gas group can be misleading unless care has been taken to normalize the amount of short-
18 term debt in the calculation of those ratios.

19
20 As to Mr. Kahal's electric group, I find his comparison to be invalid unless he has made
21 some required adjustments or has recognized other anomalies. For example, Mr. Kahal's
22 electric group contains Northeast Utilities, which has a 38.1% common equity ratio.

1 Northeast Utilities is a highly leveraged company that is atypical of the electric industry
2 generally. Further, his electric group contains Consolidated Edison, NSTAR and PEPCO
3 Holdings which carry securitized debt on their balance sheet.¹ Securitized debt has been
4 issued for transition property by special purpose entities of the utility subsidiaries of
5 Consolidated Edison, NSTAR, and PEPCO Holdings. Mr. Kahal did not discuss the
6 implications of securitized debt for these companies. It also would be necessary to
7 eliminate the tax-exempt pollution control financing for Central Vermont and Northeast
8 Utilities prior to comparing their capital structures to the Company's proposed capital
9 structure.

10
11 **Q. Mr. Kahal claims that capital structure ratios that contain common equity within**
12 **the range of 45% to 50% are reasonable, and that the midpoint, or 47.5% common**
13 **equity, should be used in this case. Please respond.**

14 A. The range proposed by Mr. Kahal contains excessive debt by reference to the benchmarks
15 used in the credit rating process. According to Standard & Poor's Corporation ("S&P"),
16 the Company has an "excellent" business risk profile (as noted by Mr. Kahal) and a
17 "significant" financial risk profile (not mentioned by Mr. Kahal). Based upon the
18 business and financial risk matrix published by S&P that is shown below, a company
19 with "excellent" business and "significant" financial risk scores would be assigned an A-
20 rating.

¹ I have also used Consolidated Edison and PEPCO Holdings in my proxy group and have adjusted for securitized debt.

BUSINESS AND FINANCIAL RISK PROFILE MATRIX

Business Risk Profile	Financial Risk Profile					
	Minimal	Modest	Intermediate	Significant	Aggressive	Highly Leveraged
Excellent	AAA	AA	A	A-	BBB	-
Strong	AA	A	A-	BBB	BB	BB-
Satisfactory	A-	BBB+	BBB	BB+	BB-	B+
Fair	-	BBB-	BB+	BB	BB-	B
Weak	-	-	BB	BB-	B+	B-

1 And indeed, the Company has an A- corporate credit rating (“CCR”) from S&P, which is
2 compatible with an “excellent” business profile and a “significant” financial profile.

3

4 **Q. Based on S&P’s benchmarks, what is the degree of debt leverage that is associated**
5 **with this rating?**

6 A. According to the indicative ratios expected by S&P for a company with a “significant”
7 financial risk score, the total debt, including short- and long-term debt, is in the range of
8 45% to 50%. These indicative values are shown below.

FINANCIAL RISK INDICATIVE RATIOS (CORPORATE)

Financial Risk Profile	FFO/Debt (%)	Debt/EBITDA (x)	Debt/Capital (%)
Minimal	greater than 60	less than 1.5	less than 25
Modest	45-60	1.5-2	25-35
Intermediate	30-45	2-3	35-45
Significant	20-30	3-4	45-50
Aggressive	12-20	4-5	50-60

9 Based upon the debt ratios shown above, the complement of the debt ratios would
10 provide equity ratios (including common equity and preferred stock) within the range of
11 50% to 55%. These are the parameters that should be used to gauge the reasonableness
12 of the ratios in this case. Therefore, Mr. Kahal’s proposed range of 45% to 50% is

1 understated, and instead should be 50% to 55%. The Company's proposed common
2 equity ratio of 50.05% fits within that range, albeit on the low side. Therefore, when
3 actual capital structure ratios are calculated after the debt offering is completed by the
4 Company, a common equity ratio of 50% is entirely reasonable.

5
6 **IV. COMMENTS ON MR. KAHAL'S RETURN ON EQUITY ANALYSES**

7 **A. PROXY GROUP COMPANIES**

8 **Q. Mr. Kahal uses electric companies that he labels as primarily delivery service**
9 **utilities. Is this selection reasonable?**

10 A. I do not believe so. In the context of the Company's revenue decoupling mechanism
11 ("RDM") proposal, the proxy group should focus on similarly situated electric utilities
12 that have decoupling. Such focus is not only compatible with this proposal, but it would
13 also align the electric group with the gas group proposed by Mr. Kahal that is dominated
14 by companies with decoupling. As such, there should be no proposed adjustment to the
15 Company's cost of equity if the Commission adopts the Company's RDM proposal
16 because the cost of equity derived from my proxy group already reflects the risk
17 implications of the proposed RDM.

18
19 **Q. What about the natural gas distribution companies considered by Mr. Kahal?**

20 A. There is no need to consider gas distribution companies to measure the cost of equity for
21 the Company due to the availability of adequate data for electric utilities. Although Mr.
22 Kahal applied specific screening criteria to assemble his electric group of seven (7)

1 companies that were selected from a total of fifty-four (54) electric companies followed
2 by Value Line, his natural gas group only eliminated three (3) companies from the entire
3 Value Line gas utility group. Mr. Kahal has not explained why the gas group should
4 comprise 75% of all gas companies, but his electric group should comprise only 13% of
5 the electric companies.

6
7 **B. DISCOUNTED CASH FLOW**

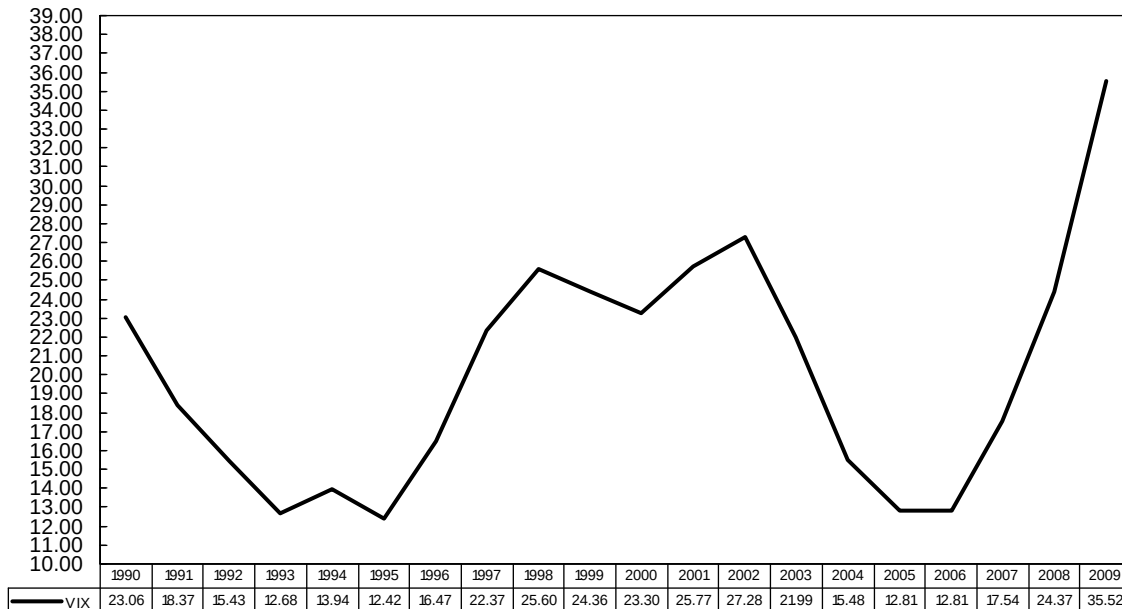
8 **Q. Should only a single approach, such as DCF, be used to measure the cost of equity**
9 **for the Company?**

10 A. No. In my opinion, no single approach is sufficiently reliable to adequately establish the
11 cost of equity without further verification. This is particularly true today given the wide
12 swings in share values and the overall financial market uncertainty that currently exists.
13 The behavior of the Chicago Board Options Exchange (“CBOE”) Volatility Index (i.e.,
14 “VIX”) indicates that the risk of common stocks is relatively high at this time. The VIX
15 is based on real-time prices of options on the S&P 500 Index, and is designed to reflect
16 investors’ consensus view of future (30-day) expected stock market volatility.

17
18 **Q. How has the VIX performed since its inception?**

19 A. The graph shown below indicates the yearly average of the VIX since 1990.

CBOE Volatility Index®



The volatility of the stock market is today significantly higher than in the past several years. The DCF model does not provide an adequate reflection of the high risk characteristics of stocks revealed by the VIX, and as such provides only a partial reflection of the risk associated with owning common stocks particularly in today's financial and economic environment.

Q. Mr. Kahal indicates that the DCF method is heavily emphasized in rate cases. Does this justify special emphasis on the DCF method?

A. No. The investment community uses other models in addition to the DCF model in their valuation analysis of common stocks. Likewise, regulators in many state jurisdictions rely on more than one method to determine the cost of equity. Since all cost of equity

1 methods contain certain unrealistic and overly restrictive assumptions, the use of more
2 than one method will capture the multiplicity of factors that motivate investors to commit
3 capital to an enterprise (i.e., current income, capital appreciation, preservation of capital,
4 level of risk bearing, etc.).

5
6 **Q. What form of the DCF model has been employed in this case?**

7 A. The constant growth form of the DCF model has been used by Mr. Kahal and me in this
8 case. However, it must be recognized that this version of the DCF model is not without
9 its limitations because many of the assumptions which must be made to utilize this model
10 are simply not realistic. According to the theory of the constant growth form of the DCF,
11 future earnings per share, dividends per share, book value per share, and price per share
12 will all appreciate at the same rate absent any change in price-earnings multiple. There is
13 no evidence that these conditions actually prevail in the equity market.

14
15 **Q. Do you have any other concerns regarding the DCF model?**

16 A. There is an element of circularity in the DCF model when applied in public utility rate
17 cases. This is because investors' expectations for the future depend upon regulatory
18 decisions. Therefore, the use of the DCF in rate cases ensures that regulators will
19 continue to provide high growth utilities with a return which sustains that performance.
20 On the other hand, the use of the DCF for low growth companies perpetuates that
21 performance and hinders any improvement. This then will reinforce investors'
22 expectations that regulators will grant returns which guarantee low growth. Due to this

1 circularity, the DCF model may not fully reflect the true risk of a utility because the
2 model may not deal with the high risk traits of a utility with low growth caused by poor
3 accounting returns. If the DCF approach cannot cope with general capital market
4 fundamentals, then either the assumptions underlying the DCF method are incomplete or
5 the approach is not being properly implemented.

6
7 **Q. As part of his DCF analysis, Mr. Kahal has provided dividends per share growth**
8 **rates published by Value Line. Are these growth rates useful in the DCF?**

9 A. Not at this time. The Value Line growth rates in dividends per share shown on page 4 of
10 Schedule MIK-4 and page 4 of Schedule MIK-5 are the lowest of all seven growth rate
11 indicators (i.e., Value Line, First Call, Zacks, CNN, dividends per share, book value per
12 share, and earnings retention). The reason dividends per share growth is so low is that
13 the dividend payout ratios are forecast to decline. This is shown below based on the
14 Value Line forecasts.

Electric Utility Distribution Proxy Companies	All Div'ds to Net Prof		
	2009	2010	2014
CH Energy Group	96.0%	86.0%	73.0%
Central Vermont P.S.	63.0%	56.0%	51.0%
Consolidated Edison	79.0%	74.0%	63.0%
Northeast Utilities	51.0%	52.0%	53.0%
NSTAR	65.0%	63.0%	61.0%
PEPCO Holdings	90.0%	72.0%	62.0%
UIL Holdings	91.0%	87.0%	76.0%
Average	<u>76.4%</u>	<u>70.0%</u>	<u>62.7%</u>

Gas Utility Distribution Proxy Companies	All Div'ds to Net Prof		
	2009	2010	2014
AGL Resources	64.0%	60.0%	57.0%
Atmos Energy	63.0%	51.0%	56.0%
LaClede Group	53.0%	60.0%	55.0%
Nicor, inc.	70.0%	65.0%	57.0%
NW Natural Gas	56.0%	59.0%	58.0%
Piedmont Natural	67.0%	65.0%	65.0%
South Jersey Ind.	51.0%	50.0%	50.0%
Southwest Gas	54.0%	52.0%	50.0%
WGL Corp.	59.0%	59.0%	60.0%
Average	<u>59.7%</u>	<u>57.9%</u>	<u>56.4%</u>

- 1 **Q. Mr. Kahal also shows forecasts of book value per share growth. Please comment.**
- 2 A. Use of book value per share growth as shown on page 4 of Schedule MIK-4 and page 4
- 3 of Schedule MIK-5 is inapplicable in the DCF analysis because stocks do not trade at

1 constant market-to-book ratios, which makes book value per share growth the incorrect
2 focus in the DCF analysis.

3
4 **Q. Did Mr. Kahal also provide information concerning earnings retention growth?**

5 A. Yes. However, the earnings retention growth rates as shown on page 4 of Schedule MIK-
6 4 and page 4 of Schedule MIK-5 are understated based on the Value Line source.

7
8 **Q. Please explain.**

9 A. In presenting his earnings retention rates, Mr. Kahal relied upon the Value Line forecasts.

10 These returns are calculated with year-end values, rather than average book values.

11 Value Line defines “return on equity,” which forms the basis of earnings retention growth
12 after payment of common dividends, as follows:

13 Percent Earned Common Equity – net profit less preferred
14 dividends divided by common equity (i.e., net worth less preferred
15 equity at liquidation or redemption value), expressed as a
16 percentage. See Percent Earned Total Capital.

17
18 Without an adjustment to convert the Value Line forecasts from year-end to average book
19 values, there is a downward bias in the results. This is because with an increasing book
20 value driven by retention growth, the average book value will be less than the year-end
21 book value. For that reason, the Federal Energy Regulatory Commission (“FERC”)
22 adjusts the year-end returns to derive the average yearly return, using the formula $2(1 + G) / (2 + G)$ (see 92 FERC ¶ 61,070). Generally speaking, this adjustment increases the
23 earnings retention growth. I have used a variant of the FERC’s adjustment procedure to
24 detect any downward bias in the figures reported by Mr. Kahal.
25

1 **Q. Has Mr. Kahal included external financing growth in his earnings retention rate**
2 **growth?**

3 A. No. This omission further understates his growth rate. Forecasts by Value Line indicate
4 that future growth from external stock financing will add to the growth in equity.
5 Frequent sales of stock at above book value add to the growth rate for the electric
6 companies. This would result in an internal/external growth rate higher than that shown
7 by Mr. Kahal.
8

9 **Q. How would the earnings retention growth rate be affected by these two**
10 **adjustments?**

11 A. By moving from year-end to average book values, the returns on book common equity
12 increase by 0.35% in the case of the gas group and by 0.40% in the case of the electric
13 group. The resulting earnings retention ratio increases by 0.17% in the case of the gas
14 group and by 0.18% in the case of the electric group. Further, the external growth rate
15 obtained by issuing new shares of common stock provides external growth of 0.81% in
16 the case of the gas group and 0.28% in the case of the electric group. In sum, the
17 resulting earnings retention growth rates would become 5.98% in the case of the gas
18 group and 3.96% in the case of the electric group.
19

20 **Q. With regard to the growth component of the DCF formula, do you believe that the**
21 **growth rates in dividends per share, book value per share and earnings retention as**
22 **reported by Mr. Kahal are reasonable for DCF purposes?**

1 A. No. These growth rates are clearly lower than all of the analysts' forecasts for the
2 electric companies. For example, the average analysts' forecast of earnings growth is
3 4.87% for the electric group, while the average of the dividends, book value, and earnings
4 retention growth is just 3.05% ($1.86\% + 3.79\% + 3.50\% = 9.15\% \div 3$). For the gas
5 group, the 5.24% earnings growth rate substantially exceeds the 4.16% ($3.33\% + 4.33\%$
6 $+ 4.83\% = 12.49\% \div 3$) average of the dividends, book value, and earnings retention
7 growth. This clearly shows that the dividends, book values, and earnings retention
8 growth play no role in the DCF analysis. Moreover, it is instructive to note that Professor
9 Gordon, the foremost proponent of the DCF model in rate cases (and the individual
10 whose name is most commonly associated with the DCF model), has determined that the
11 best measure of growth in the DCF model is analysts' forecasted earnings per share
12 growth. Hence, to follow Professor Gordon's findings, earnings per share forecasts must
13 be given primary weight. As such the growth rate that should be used in the DCF model
14 is 4.87% for his Electric Group, and 5.24% for his Gas group (see page 3 of Schedules
15 MIK-4 and MIK-5, respectively).

16
17 **Q. Mr. Kahal criticized the leverage adjustment that you propose to account for the**
18 **divergence of market capitalization and book value capitalization. Please comment.**

19 A. It must be recognized that, in order to make the DCF results relevant in the ratesetting
20 context, the market-derived cost rate cannot be used without modification. The
21 importance of the leverage modification to the DCF results was fully supported in my
22 direct testimony, wherein it was shown that the market value of the equity in the RDM

1 Electric Group's capitalization was much higher than its book value. This relationship is
2 indicated by the market value common equity ratio of 50.98% compared to a book value
3 common equity ratio of 48.74% (see page E-12 of Workpaper NG-PRM-E of my direct
4 testimony). To make the market-derived DCF results applicable in the ratesetting
5 context, it is necessary to account for the higher financial risk that arises from the lower
6 common equity ratio measured by book value capitalization as compared to the higher
7 common equity ratio measured by market capitalization. Because book value capital
8 structures are used instead, my adjustment procedure is required.

9
10 **Q. Mr. Kahal claims that the Company does not have a market based capital structure**
11 **because its stock is not publicly traded. Does this invalidate your leverage**
12 **adjustment?**

13 A. No. My cost of equity analysis is based on my RDM Electric Group, which contains
14 companies with publicly traded stocks. Mr. Kahal likewise uses publicly traded
15 companies in his various proxy groups. The leverage adjustment that I proposed is based
16 on the market value capitalization of the RDM Electric Group that I use as a proxy to
17 measure the cost of equity for Narragansett Electric. So, as long as the RDM Electric
18 Group evidence is relevant to the cost of equity for Narragansett Electric, then the
19 leverage adjustment for the RDM Electric Group is equally valid as a component of the
20 cost of equity for Narragansett Electric.

1 **Q. Mr. Kahal asserts that investors are aware that regulators use book values in the**
2 **ratesetting process. Does this invalidate use of the leverage adjustment?**

3 A. No. Even if he is correct, it has nothing to do with my adjustment. The formulas
4 developed by Nobel laureates Modigliani and Miller contain absolutely no reference to
5 any book values. These formulas are designed to account for differences in financial risk
6 among varying capital structures (i.e., related to the proportions of debt and equity in the
7 capital structure). The issue addressed by my adjustment is associated solely with
8 financial risk (i.e., the percentage of borrowed funds in the capital structure) and the risk
9 difference between market values and book values. In addition, my DCF calculations
10 produce the returns that investors expect on their market value. The DCF formula is
11 derived from the standard valuation model: $P = D / (k - g)$, where P = price, D = dividend,
12 k = the cost of equity, and g = growth in cash flows. The assumptions implicit in the
13 model were described in my direct testimony. By rearranging the terms, we obtain the
14 familiar DCF equation: $k = D/P + g$. All of the terms in the DCF equation represent
15 investors' assessment of expected future cash flows that they will receive in relation to
16 the value that they set for a share of stock (" P "). The need for the leverage adjustment
17 arises when the results of the DCF model (" k ") are to be applied to an equity ratio that is
18 different than the one shown by the market price (" P "), i.e., in this instance, the equity
19 ratio calculated from the book value capitalization. My leverage adjustment is not
20 intended, nor was it designed, to address the reasons that stock prices vary from book
21 value.

1 **Q. On pages 55-58 of his direct testimony, Mr. Kahal brings up the issue of a market-**
2 **to-book relationship and the DCF method. Is this observation on point?**

3 A. No. Market-to-book (“M/B”) ratios are entirely irrelevant to my leverage adjustment.
4 The leverage adjustment contains no factor that would express the DCF return for any
5 particular market-to-book ratio. Perhaps it is worthwhile to recap the procedure used in
6 making my adjustment, which, as previously explained, entails a three-step process. In
7 step one, the DCF cost of equity is calculated using the market price of stock and the
8 capital structure ratios are computed from the market capitalization of both the debt and
9 equity of a firm. In step two, a completely unlevered cost of equity is calculated, as if the
10 firm were 100% equity financed. In the third step, a relevered cost of equity is calculated
11 with the capital structure determined from the book value capitalization. There is
12 absolutely no reference to M/B ratios in the process of adjusting the DCF return for
13 application to the book value capitalization. Simply stated, the rate of return on common
14 equity is the unleveraged cost of capital (or equity return at 100% equity) plus a term(s)
15 reflecting the increase in financial risk resulting from the use of leverage in the capital
16 structure. Multiple terms are used in the case of both debt and preferred stock. The
17 resulting return is the one that is necessary for the utility to earn on its own book value
18 capital structure to reflect the financial risk that varies from the return that applies to the
19 market value capital structure.

20
21 I must once again make it clear that my leverage adjustment is not intended to achieve,
22 and contains no factor for, a particular market-to-book ratio. It merely expresses the cost

1 of equity as the unleveraged return plus compensation for the additional risk of
2 introducing debt and/or preferred stock into the capital structure. The return for the RDM
3 Electric Group applicable to its equity with no debt in its capital structure (i.e., the cost of
4 capital is equal to the cost of equity with a 100% equity ratio) is 9.37% (see page E-13 of
5 Workpapers NG-PRM-E). To this, I add 1.72% compensation for the RDM Electric
6 Group's average 50.14% debt ratio, plus 0.08% for an average 1.12% preferred stock
7 ratio. The sum of the parts is 11.17% ($9.37\% + 1.72\% + 0.08\%$). There is no need to
8 even address the cost of equity in terms of $D/P + g$. To express this same return in the
9 context of the familiar DCF model, I summed the 5.02% dividend yield, the 6.00%
10 growth rate, and the 0.15% for the leverage adjustment in order to arrive at the same
11 11.17% ($5.02\% + 6.00\% + 0.15\%$) return. I know of no means to mathematically solve
12 for the 0.15% leverage adjustment by expressing it in the terms of any particular
13 relationship of market price to book value. The 0.15% adjustment is merely a convenient
14 way to compare the 11.02% return computed directly with the Modigliani & Miller
15 formulas to the 11.17% return generated by the DCF model based on $D/P + g$. There can
16 be no dispute that a firm's financial risk varies with the relative amount of leverage
17 contained in its capital structure.

18
19 In further response to Mr. Kahal, while he may point to regulatory commissions that have
20 not permitted a market-to-book adjustment to DCF, this is a non-issue because I have not
21 proposed a market-to-book adjustment. Hence, his point is not relevant.

1 **C. CAPITAL ASSET PRICE MODEL**

2 **Q. What betas does Mr. Kahal include in his CAPM calculation?**

3 A. In this case, Mr. Kahal has presented betas obtained from YahooFinance.com and
4 MSNMoney.com, as well as Value Line. Apparently, Mr. Kahal has not used the betas
5 from Yahoo Finance and MSNMoney in his CAPM analysis, and instead has relied upon
6 Value Line betas. I agree that the Yahoo Finance and MSNMoney betas should not be
7 used because there is no indication of the independent variable used by these sources, the
8 frequency of the measurement period, whether dividends have been included in the
9 calculations, and whether the betas have been adjusted for regression bias or other
10 reasons. Therefore, it is clear that Value Line is the only suitable source of betas in this
11 case.

12
13 **Q. Mr. Kahal has used a market premium of 7.0%, which indicates a total market**
14 **return of 11% (i.e., 7.0% + 4.0%). Will you comment?**

15 A. In many prior cases where Mr. Kahal presented rate of return testimony, he used a range
16 of 11% to 12% as his total market return. A total market return of 11% is at the low end
17 of the range of returns previously used by Mr. Kahal. My analysis shows that 11% total
18 market return is too low and the Merrill Lynch Quantitative Profiles similarly shows that
19 a total market return of 12.1% is indicated for the S&P 500. Additional evidence of the
20 total market return is:

Value Line Return				
As of:	Dividend Yield		Median Appreciation Potential	Median Total Return
2-Oct-09	2.1%	+	11.58%	= 13.68%

DCF Result for the S&P 500 Composite				
D/P	(1+.5g)	+	g	= k
2.13%	(1.0446)	+	8.91%	= 11.13%
where: Price (P)	at	31-Aug-09	=	1020.62
Dividend (D)	for	2nd Qtr. '09	=	5.44
Dividend (D)		annualized	=	21.76
Growth (g)		First Call EpS	=	8.91%

Summary Total Market Return:	
Value Line	13.68%
S&P 500	11.13%
Average	<u>12.41%</u>

These data confirm that the high end of the range of total market returns is indicated at this time. The resulting market premium would be 8% (12% - 4%).

Q. Mr. Kahal also argues against recognition of a size adjustment to the CAPM. Please comment.

A. My direct testimony fully supported a separate size adjustment in the CAPM because the financial literature demonstrates that this risk element is not accounted for in the model. As shown by the capital structure data presented on page 2 of Schedule NG-PRM-1, the Company's pro forma common equity will be \$637.5 million after restructuring. But rather than use this level of capitalization to make the size adjustment, which would warrant a much higher micro-cap adjustment, I used the more conservative mid-cap size adjustment that is related to the RDM Electric Group.

1 As to Mr. Kahal's observation that the Company is affiliated with National Grid USA,
2 which is a much larger entity, I explained in my direct testimony that the Company must
3 be judged on its own merits in this case. That is to say, the Company's stand-alone risk
4 characteristics must be addressed in this case in order to avoid cross-subsidization that
5 would occur if the Company's affiliation with National Grid USA were part of the cost of
6 equity analysis. Therefore, any referenced by Mr. Kahal to National Grid USA is not
7 relevant to the size adjustment or other risk factors that influence the Company's cost of
8 equity.

9
10 **D. RISK PREMIUM METHOD**

11 **Q. Do you believe the Risk Premium method provides significant evidence of the cost of**
12 **equity?**

13 A. Yes. In my opinion, the Risk Premium results should be given serious consideration.
14 The Risk Premium method is straight-forward, understandable and has intuitive appeal
15 because it is based on a company's own borrowing rate. The utility's borrowing rate
16 provides the foundation for its cost of equity which must be higher than the cost of debt
17 in recognition of the higher risk of equity. So while Mr. Kahal declines to use the Risk
18 Premium approach to measure the Company's cost of equity, it is an approach that
19 provides a direct and complete reflection of a utility's risk and return because it considers
20 additional factors not reflected in the beta measure of systematic risk.

1 **Q. Please respond to Mr. Kahal's testimony concerning his alternative proposal that**
2 **would include a risk premium based upon a calculation using the arithmetic and**
3 **geometric mean returns, without consideration of the median.**

4 A. First of all, Mr. Kahal's result of the risk premium approach that produces an 8.16%
5 return based upon the geometric mean is simply outside the range of reasonable returns.
6 Second, Mr. Kahal failed to develop a median risk premium that represents a key
7 measure of central tendency. Indeed, Mr. Kahal acknowledges the importance of the
8 median value in his discussion of the analyst's forecasts from sources, such as First Call,
9 Zacks and CNNf. Moreover, Value Line also prominently uses the median value in its
10 publication. The median value cannot be ignored.

11
12 **E. COMPARABLE EARNINGS**

13 **Q. Mr. Kahal disagrees with your Comparable Earnings approach. Please comment.**

14 A. As a preliminary matter, this approach has been used by me solely as a check on the
15 market models (i.e., DCF, Risk Premium, and CAPM) and it played no direct role in my
16 recommended 11.6% cost of equity for the Company in this case. The Comparable
17 Earnings approach was established in the landmark Bluefield & Hope decisions, which
18 set forth the two principal standards of a fair return, namely, comparability and capital
19 attraction. In the Hope decision, the United States Supreme Court defined these
20 requirements: "... the return to the equity owner should be commensurate with returns on
21 investments in other enterprises having corresponding risks. That return, moreover,
22 should be sufficient to assure confidence in the financial integrity of the enterprise, so as

1 to maintain its credit and attract capital.” The Comparable Earnings approach satisfies
2 the comparability standard.

3
4 **Q. Mr. Kahal raises the issue of large premiums to the book values in his critique of**
5 **your Comparable Earnings approach. Please comment.**

6 A. The introduction of the market premium to book value, as part of his critique of my
7 Comparable Earnings method, provides belated recognition of the factors I discussed
8 above regarding the DCF and CAPM. Market values play no role in the Comparable
9 Earnings approach that focuses on book values. It is for this reason that the results of the
10 Comparable Earnings approach can be applied directly in the ratesetting process that
11 focuses on book value.

12
13 **V. REBUTTAL CONCLUSION**

14 **Q. What are your conclusions based on your analysis of Mr. Kahal’s testimony?**

15 A. In my opinion, Mr. Kahal’s proposed cost of equity is too low in today’s markets. The
16 equity return proposed by Mr. Kahal fails to adequately reflect the higher risk for equities
17 generally. Furthermore, the Commission should calculate the Company’s weighted
18 average cost of capital using the Company’s actual capital structure after the issuance of
19 new long-term debt and the restructuring of its capitalization. The Company’s weighted
20 average cost of capital should also reflect the actual cost of the new long-term debt. The
21 associated common equity ratio should be targeted at approximately 50%, which would

1 be consistent with the criteria needed to maintain the Company's A- credit rating that is
2 considered in the credit rating process.

3

4 **Q. Does this conclude your rebuttal testimony?**

5 A. Yes.

PRE-FILED REBUTTAL TESTIMONY

OF

JULIE M. CANNELL

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1 **I. INTRODUCTION**

2 **Q. Please state your name, employer, and business address.**

3 A. My name is Julie M. Cannell. I am the president of my own advisory firm, J.M. Cannell,
4 Inc. My business address is P.O. Box 199, Purchase, NY 10577.

6 **Q. Please describe your professional and educational background.**

7 A. My firm, J.M. Cannell, Inc., provides investor-related advisory services to electric utility
8 companies and other firms and organizations with an interest in the industry. Prior to
9 establishing my firm in February 1997, I was employed by the New York-based
10 investment manager, Lord Abbett & Company, from June 1978 to January 31, 1997.
11 During my tenure with Lord Abbett, I was a securities analyst specializing in the electric
12 utility and telecommunications services industries; portfolio manager of America's
13 Utility Fund, an equity utility mutual fund, for which Lord Abbett was a sub-advisor;
14 portfolio manager of numerous institutional equity portfolios; and co-director of Lord
15 Abbett's Equity Research Commission.

16
17 My educational credentials include a B.A. from Mary Baldwin College, M.Ln. from
18 Emory University, and M.B.A. from Columbia University. I am also a Chartered
19 Financial Analyst (C.F.A.).

20
21 I have been a member of the Wall Street Utility Group, an organization of security and
22 credit rating analysts having an expertise in the utility industry, for over thirty years.

1 **Q. Have you submitted testimony previously before any state regulatory agencies?**

2 A. Yes, I have. I have submitted pre-filed testimony on behalf of investor-owned utilities
3 before Public Service or Public Utility Commissions in the states of Arizona,
4 Connecticut, Kansas, Massachusetts, Missouri, Nevada, New York, Oklahoma,
5 Pennsylvania, South Carolina, Texas, Virginia, Washington, and Wisconsin.
6

7 **Q. Have you had additional regulatory interaction?**

8 A. Yes. Since 2004, I have served as a consultant on retainer to the Edison Electric Institute,
9 with extensive involvement in an ongoing initiative geared toward fostering and
10 improving communications between state regulators and the investment community.
11 This initiative has centered on a series of forums held throughout the United States to
12 bring these two interests together, with the sponsorship of the Edison Electric Institute
13 and facilitated by Robert W. Gee, President of Gee Strategies, LLC (former Assistant
14 Secretary for Policy and International Affairs for the U.S. Department of Energy and
15 Chairman of the Public Utility Commission of Texas). In addition to helping structure
16 these dialogues, my role has been to moderate panel discussions of equity and debt
17 security analysts.
18

19 I have also conducted several studies of investor perceptions of regulatory issues.
20 Further, I have written articles addressing the implications for utilities and state
21 regulators of various topical issues, including the current electric industry capital
22 expenditure cycle and the financial crisis.
23

1 **Q. What is the scope of your rebuttal testimony in this proceeding?**

2 A. My testimony responds to the Direct Testimony of Mr. Matthew Kahal, which was
3 submitted in this proceeding on behalf of the Rhode Island Division of Public Utilities
4 and Carriers (the “Division”). Specifically, I will provide comments on two areas: (1) the
5 perspective of investors with respect to the return on equity for The Narragansett Electric
6 Company d/b/a National Grid (“Company”); and (2) the importance of regulatory support
7 in facilitating the Company’s access to the capital markets at a reasonable cost.

8
9 **Q. Please summarize how your experience positions you to provide testimony on the**
10 **viewpoint of investors in this case.**

11 A. As a securities analyst, I specialized in the financial analysis of the electric utility
12 industry and the individual companies comprising it. As a portfolio manager, I applied
13 that knowledge, along with investment fundamentals, to make investment decisions on
14 behalf of institutions and individual investors. In addition to this experience, I have
15 reviewed various reports of industry analysts and rating agencies addressing the
16 Company and its regulatory situation.

17
18 **Q. As an analyst or portfolio manager, did you follow the Company or its predecessor**
19 **parent, New England Electric System?**

20 A. Yes, I did. Both Lord Abbett and America’s Utility Fund periodically maintained a
21 holding in the common stock of New England Electric System.

1 **Q. Please summarize the key points of your testimony.**

2 A. As my testimony will explain, Mr. Kahal's testimony does not fully account for the fact
3 that investors now require a higher return when investing in the electric utility industry
4 due to the changing nature of the industry through a hybrid deregulated structure and
5 attendant increased risk. That risk level has also been raised due to the major capital
6 expenditure cycle on which the industry has embarked, and is exacerbated most recently
7 by the global financial crisis. Even prior to the onset of the crisis last fall, the investment
8 industry itself had experienced major changes in recent years, including a dramatic
9 growth in the amount of capital controlled by institutional investors and hedge funds.
10 Performance pressures have shortened significantly the timeframe during which an
11 investment must realize its expected return.

12
13 In making their assessments of utility companies, credit rating agencies and investors
14 consider various factors; key among these factors is the regulatory environment.
15 Regulators influence a utility's capital structure and returns that may be earned on that
16 capital. In turn, those factors determine a company's creditworthiness, as well as its
17 ability to provide stable earnings and dividends.

18
19 In my judgment, the investment community would find an 11.6 percent return on equity
20 ("ROE") for the Company, as recommended by Mr. Paul R. Moul, to be reasonable. This
21 level of allowed return would provide the Company with the necessary cash flow to help
22 fund its capital expenditure program, while meeting the expectations of equity investors.

1 Importantly, an allowed ROE of 11.6 percent would benefit customers by strengthening
2 the Company's finances and lowering its future cost of capital.

3
4 **Q. Please describe how your testimony is organized.**

5 **A.**There are three parts to my testimony.
6

7 **How Investors Evaluate Investments in Utility Companies.** This section responds to
8 Mr. Kahal's testimony regarding the investment risk of electric utilities, discussing why
9 investors choose to invest in electric utilities with particular emphasis on the reasons that
10 the regulatory climate in which a utility operates is of such importance to investors. This
11 section of the testimony also discusses why the risk of investing in the electric utility
12 industry has risen substantially in recent years on an industry-wide basis, and why
13 markets today react so swiftly and strongly to unfavorable news about a company. It
14 further details the risk present in distribution-only companies.

15
16 **Investors' Perceptions Related to the Present Proceeding.** This section also responds
17 to Mr. Kahal's discussion regarding investments in electric utilities, reviewing the
18 investment community's perceptions of the Company and Rhode Island regulation. This
19 review is based on a number of recent publications by credit rating agencies and
20 investment analysts discussing their perceptions of the Company and its regulatory
21 environment.
22

1 **Return on Equity.** This section discusses the Company's request for an allowed ROE of
2 11.6 percent and responds, in part, to Mr. Kahal's testimony that a return on equity of
3 10.1 percent is reasonable. My conclusion is that the Company's proposal is one that
4 investors would view as important and constructive. In that regard, an allowed ROE of
5 11.6 percent should generate a solid stream of earnings and cash flow and would likely be
6 viewed favorably by the investment community at a time when increased financial
7 stability is very important to the Company.

8
9 **II. HOW INVESTORS EVALUATE INVESTMENTS IN UTILITY COMPANIES**

10 **Q. Why is it important to consider the opinions of the investment community in setting**
11 **the allowed ROE in a ratemaking proceeding?**

12 A. Electric utilities are in the business of constructing, maintaining and replacing the
13 infrastructure needed to give their customers safe, reliable and efficient service. Electric
14 delivery is a capital-intensive business. Investors provide the capital necessary to
15 maintain and expand a utility's infrastructure, which in turn enables utilities like the
16 Company to provide reliable service to customers. The terms on which the Company is
17 able to obtain that capital have a direct and measurable impact on customers and the
18 amounts they pay for distribution service. For example, if credit rating agencies such as
19 Moody's Investors Service ("Moody's") or Standard & Poor's ("S&P") believe that the
20 utility's revenues will be diminished by adverse business or regulatory decisions, those
21 rating agencies would lower their credit ratings for the utility, which in turns tends to
22 increase the cost of debt. And, because the cost of debt is a component of the weighted

1 average cost of capital, the increased costs of capital would be passed on to customers in
2 the form of higher rates.

3
4 The same is true for equity investors. If individual or institutional investors believe that
5 the return they are offered is too low in light of the risk involved, they will either sell
6 their stock or elect not to purchase the stock, which generally drives the stock price
7 down. Although lower stock prices would appear at first blush to be a concern only to
8 investors, lower stock prices also affect customers. When a utility has to go to the equity
9 markets to obtain capital, a relatively low stock price requires it to issue more shares of
10 stock to obtain the same amount of money that it would have received for fewer shares if
11 the per share price had been higher. Because of the resulting increase in the number of
12 shares outstanding, more dollars would have to be expended toward dividends, resulting
13 in less retained earnings for reinvestment in the company.

14
15 The corollary is that when investors believe that they are investing in a company that
16 enjoys fair, consistent regulation and a reasonable rate of return, those investors charge
17 less for their capital. And when debt and equity investors demand less for their capital,
18 utility rates remain lower and utilities have more ready access to the capital markets.
19 Thus, a utility and its ratepayers have a shared interest in meeting the expectations of
20 investors and credit rating agencies. Regulators share this interest as well, because fair
21 treatment of one utility decreases the costs of capital for all utilities in that regulatory
22 jurisdiction.

1 **Q. Are you suggesting that the Rhode Island Public Utilities Commission (the**
2 **“Commission”) should cater to the desires of investors?**

3 A. No. I realize that the Commission has to balance the interests of both investors, who
4 want consistent and constructive regulatory treatment, and customers, who want lower
5 rates. My point is that the Commission’s decision on rate of return is not simply a zero-
6 sum game. If the rate of return is within a zone of reasonableness, both the utility and
7 customers benefit. If the rate of return is set too low, both the utility and customers are
8 adversely affected because of the resulting impact on the cost of capital. The next part of
9 my testimony is devoted to explaining why the correlation of investor and shareholder
10 interests exists.

11
12 **Q. What goals lead investors to invest in electric utilities?**

13 A. Historically, electric utilities have been regarded as investment vehicles that provide
14 stable performance through the ups and downs of market cycles and changing economic
15 conditions. Electric utilities historically have earned a reasonable return even when
16 conditions were not favorable for other companies. Accordingly, electric utility stocks
17 have been particularly valuable holdings when conditions were not favorable to
18 investments in more volatile industry sectors. In other words, investors might see greater
19 returns from investment in other industries when times were good, but they would lose
20 less on electric utility stocks when times were less favorable.

21
22 In addition, the reliability of electric utility earnings streams historically has permitted
23 most of the companies to continue to pay regular dividends during both good and bad

1 economic cycles. For investors with a need for regular cash income, the prospect of
2 regular dividends has been an important consideration in making a decision to invest in
3 electric utility stocks.

4
5 Based on these factors, investors traditionally have viewed electric utility stocks as bond
6 substitutes. In other words, electric utility stocks have provided regular cash returns in
7 the form of dividends and the shares themselves were seen to have a stable underlying
8 value. Electric utilities historically have paid out a large proportion of their earnings as
9 dividends, and their large construction programs have kept them dependent on the capital
10 markets. As a result, electric utility stocks as a group have tended to move closely in line
11 with the direction of interest rates, but in an inverse relationship. That is, utility stock
12 prices rose when interest rates fell, and vice versa. These factors made electric utilities a
13 preferred investment during economic slowdowns or recessions and owning them was a
14 way of balancing the risks in a stock portfolio that included stocks in more volatile
15 industries. That historic relationship between utility stock prices and interest rates has
16 not been consistent of late. This is due to fundamental concerns that investors have about
17 the massive capital expansion program the industry is facing and the amount of capital
18 that will be required to fund it, among other issues.

19
20 **Q. Have the recent changes in the industry increased the risk of investing in electric**
21 **utilities?**

22 **A.** Yes. The predictability of the electric utility industry's earnings, across the sector, was
23 undermined in the last 10 to 15 years by the restructuring of the industry that has taken

1 place in many parts of the country, including Rhode Island. Presently, the onset of a
2 major new construction cycle is seen as posing a new and significant challenge to the
3 electric utility sector. As well, regulatory exposure has become a key focus for investors
4 as utilities face a series of rate cases raising issues related to infrastructure aging and
5 expansion, environmental requirements, smart grid investments and other cost increases.
6 These risks are in addition to those posed by technological, economic, environmental and
7 other policy changes that affect the industry. These increased risks mean that investors
8 no longer perceive electric utilities as a group as being the “safe havens” they once were.
9 Investor goals, however, have not fundamentally changed. Investors still look to electric
10 utilities primarily as defensive investments, and still look for stable performance and
11 regular dividends as the reason to invest in electric utilities. But investors also
12 understand that the investment risk in electric stocks has risen significantly. If the
13 regulatory climate in Rhode Island is perceived to no longer be supportive, current and
14 potential investors may seek alternative safe harbors for their money.

15
16 In the end, investors have a very large universe of stocks from which to select; with few
17 exceptions, they have no requirement to own electric utility stocks. Consequently,
18 investors now require a higher return for investing in the electric utility industry to
19 balance the increased risk associated with it.

20
21 **Q. How do these concerns affect the Company?**

22 A. Markets tend to make judgments about investment risks that apply to industry sectors as a
23 whole. Company-specific risk factors are additive to sector risk. In other words,

1 investors first determine the risk involved in investing in a particular sector. They then
2 add to that sector risk the specific risks applicable to individual companies.

3
4 **Q. You mentioned the industry's current construction cycle as a risk. Please elaborate.**

5 A. In its annual regulatory study, *Capital Management*, Barclays Capital extensively
6 explores the ramifications of the current construction cycle. Among the key points
7 detailed in the study are the following (*emphasis added*):

8 We are in the third year of the infrastructure build cycle for regulated
9 utilities that began in 2007. Based on our 2009 capex survey, we now
10 anticipate that the industry will proceed with a pre-dividend free cash flow
11 deficit through at least 2013, but likely significantly longer. We estimate
12 over the next five years, the industry will spend on average 2.0x its annual
13 depreciation and amortization expense growing industry rate base at an
14 average annual pace of 6.3%.

15 ---

16 We expect that the risks of this build cycle will offset much of the growth
17 opportunity in share performance through the construction period. This is
18 consistent with the investor experience in the last major infrastructure
19 cycle which extended from 1973-1984. *The headwinds we forecast will*
20 *likely come from the dilutive effect of heightened external capital funding*
21 *requirements, regulatory risk in a rising rate environment and execution*
22 *risk associated with a significant construction program. The best*
23 *performing stocks over the cycle will likely be those spending on*
24 *infrastructure with the highest public policy support, with the highest*
25 *quality balance sheets, doing business in the best regulatory jurisdictions.*

26 ---

27 *In the long term, structural headwinds should persist for regulated*
28 *utilities, owing to risks associated with capital acquisition, construction*
29 *execution, and regulatory recovery in a rising rate-base environment. The*
30 *bulk of this report is focused on these long run trends. As a result of these*
31 *trends, we would be owners of the most constructive regulatory*
32 *jurisdictions, the strongest balance sheets, and most capable*
33 *managements.*

34 ---

1 *In the intermediate term, we are looking for potential catalysts around*
2 *rate case filings and equity issuance schedules.*¹

3 **Q. What additional conclusions did Barclays draw regarding implications of the**
4 **current construction cycle?**

5 A. Barclays opined that both regulatory lag and risk premiums will be rising:

6 During periods of rising capital expenditures and rate base as well as
7 rising costs, utilities with historic test years cannot fully recover those
8 rising costs over time. That is, during periods of free cash flow [FCF]
9 deficits, revenues meant to offset depreciation, capital, and operating
10 costs, for utilities with historic test years are often delayed versus the
11 actual incurrence of these costs due to the review process.

12 As FCF deficits have increased, this has in turn increased balance sheet
13 strain, regulatory scrutiny, and execution risk. Investors may, as a result,
14 demand a higher risk premium. ...we would expect to see risk premiums
15 spike to the area of 13.5% by 2010 versus the 3.17% seen in 2008, before
16 moderating in the 11%-12% area from 2011 to 2013. Returns should move
17 lower with the increase in equity risk premiums.²

18 **Q. What are the implications of the Barclays' analysis regarding the equity risk**
19 **premium associated with utility investments?**

20 A. As graphically displayed in Figure 25³ in the Barclays report, the equity risk premium has
21 begun to return to levels not seen since the 1970s and 1980s, when the industry's last
22 major construction program occurred. It also bears mention that spreads on eight new
23 issues of common stock issued over the last year ranged from approximately 400-900
24 basis points relative to the 10-year Treasury rate, reflecting the fact that the market is now
25 demanding higher returns from utility investments.

¹ Barclays Capital, Capital Management, July 16, 2009.

² Ibid.

³ Ibid.

1 **Q. Relative to the last major construction cycle, how is the industry currently**
2 **positioned to proceed through this phase of building?**

3 A. An article published last year in Electric Perspectives⁴ suggests that there are both
4 similarities and differences in factors characterizing this cycle and the one that occurred
5 in 1970s-80s. It is too early in the process to determine whether history will be repeated
6 in this cycle. However, one critical difference worth noting is that the industry's current
7 average credit rating is BBB, which is weaker than the single A average rating during the
8 prior cycle.⁵ This poses a significant risk for investors.

9
10 **Q. Can you offer additional perspective on the industry's situation in the context of its**
11 **major capital expenditure initiative?**

12 A. In an April 2009 publication, JP Morgan, highlighting the ways in which the risk profile
13 of electric utilities is becoming more in line with industrial companies, detailed the
14 degree to which utilities are more dependent on the financial markets than are their
15 industrial counterparts.⁶ Key points included in the study are:

- 16 • Weaker operating cash flow: The typical utility spent 134 percent of
17 operating cash flow on capex in the last year versus 35 percent for other
18 sectors. The typical utility's operating cash flow covers only roughly 60

⁴ Julie M. Cannell, "The Capex Cycle," Electric Perspectives, May-June 2008.

⁵ Julie M. Cannell, "The Financial Crisis and Its Impact on the Electric Utility Industry," Prepared for the Electric Utility Industry, February 2009.

⁶ JP Morgan, Challenges Ahead: Building a New Power Infrastructure in Today's Financial Paradigm, April 2007, at 1-2.

1 percent of its capex and dividend expenditures, versus 175 percent for the
2 typical industrial company.

- 3 • Fragile liquidity: Utilities' firm value is only 2 percent in cash versus 8
4 percent for non-utilities. Utilities' bank lines provide 76 percent of their total
5 liquidity versus 57 percent for industrials.
- 6 • Weaker credit ratings: The average utility credit rating is BBB, versus BBB+
7 for industrial companies, during a time of heightened financial uncertainty and
8 a daunting utility capex program.

9
10 JPMorgan's findings confirm that industrials enjoy a much stronger cash position than
11 utilities. Stated another way, the data reflects how much more reliant utilities are than
12 industrials on the capital markets during a period in which utilities face dramatic levels of
13 increased capex. In other words, risks associated with electric utility investments are
14 increasing.

15
16 **Q. Your discussion of risks thus far has pertained to the industry as a whole. Please**
17 **now address the specific risks the Company is facing.**

18 A. Like many other utilities, the Company has a large construction program. Based on the
19 testimony of Mr. Pettigrew, the Company has seen a sharp increase in capital
20 expenditures over the past several years and are expected to total some \$59 million for
21 calendar year 2009. For the rate year in this proceeding, or calendar year 2010, capital
22 expenditures are projected to grow to approximately \$75 million.

1 **Q. Does the Company face additional risks in a competitive market for energy?**

2 A. Yes, they do. As a wires-only company focusing on energy distribution, the Company
3 has all of its assets concentrated in a single line of business and therefore is fully exposed
4 to any risks, including those pertaining to size and scope, which may affect the core
5 business. In addition, the Company makes no profit from the production or procurement
6 of electricity, and is no longer driving or controlling the cost of power to the customer.
7 As commodity costs increase, customers and regulators will subject the only part of the
8 value chain they can control—the distribution business—to further financial pressures.

9
10 **Q. What additional risk factors are facing wires-only companies today?**

11 A. High commodity prices have contributed to a reluctance on the part of politicians and
12 regulators to subject consumers to additional rate increases, as was true in Maryland and
13 Illinois in 2006.

14
15 A related factor is increasing environmental requirements such as RGGI, RPS, or RES, as
16 well as other forms of carbon-reducing regulation, coupled with a significantly
17 heightened public awareness of climate issues. Although utilities have long faced
18 environmental compliance costs, these types of expenditures are likely to rise to a new
19 level under the Obama Administration. Even though the Company does not own
20 generation or profit from power purchases, the costs associated with incremental levels of
21 environmental compliance will be reflected in the price of purchased power. Again, this
22 puts pressure on total costs and thus makes it more difficult for regulatory commissions
23 to accept rate increases.

1 **Q. Have further risks related to wires-only companies presented themselves?**

2 A. Yes. With a major construction program now underway in the industry, it is clear that
3 there will be more regular rate cases, which raise questions about the timing and certainty
4 of a utility's cash recovery of costs. These rate proceedings will be driven by the
5 substantial current-dollar costs of maintaining a mature utility infrastructure.

6
7 **Q. You've discussed the mounting risks you see a distribution company facing. Do**
8 **those risks have the potential to reduce the company's earnings and cash flow**
9 **streams and increase their volatility?**

10 A. Yes. A single line of business increases exposures to enterprise credit risk, operating
11 issues, prospective new costs, and technology issues, all of which can have negative
12 financial ramifications. Moreover, because these factors are in large part beyond a
13 company's control, the company's investors have little guidance and more uncertainty.
14 Uncertainty leads to investor concern and demands for higher investment returns.

15
16 **Q. Are investors concerned about state regulation in the context of these challenges?**

17 A. Yes. Nationally, the pace of rate case filings, which are already becoming more frequent,
18 is expected to accelerate. From an investor's perspective, each regulatory proceeding
19 introduces a period of uncertainty for a utility. Among the unknowns are the equity
20 return the company will be allowed to earn, the equity base on which that return can be
21 earned, the extent to which costs—both historical and future— can be recovered, and the
22 degree to which the rate case will prompt a negative political reaction. In other words,
23 the utility's future earnings power is thrown into question until the case is decided.

1 Because that earnings power is the basis for an investment in the company, the
2 constructiveness of state regulation is a critical factor to investors.
3

4 **Q. Please elaborate on the uncertainty surrounding allowed returns on equity.**

5 A. Recent years have seen allowed ROE levels fall, even as industry risks have risen.
6 According to data provided by Regulatory Research Associates,⁷ average allowed ROEs
7 fell from 12.70 percent in 1990 to 10.36 percent in 2007. In 2008, the number rose
8 slightly to 10.46 percent and through second quarter 2009, the average ROE was 10.52
9 percent. Average ROE allowances in the third quarter 2009 dipped slightly to 10.46
10 percent. It bears mention, however, that there were only three data points in the most
11 recent quarter; four additional cases resolved during the period did not specify returns.
12 Of particular concern is that the average allowed ROE has been below 11 percent for the
13 past six years, even as industry risk associated with the major construction cycle and
14 other pressures has begun to mount.
15

16 **Q. Do investors have additional regulatory concerns?**

17 A. Yes. Many states offer little assurance of cost recovery, especially in the context of a
18 major capital expenditure program, by including construction work in progress in rate
19 base or by pre-approving capital improvement programs for more timely recovery than
20 allowed through base-rate proceedings. This is a significant deterrent to investors with
21 long memories relative to the last construction cycle, during which billions of investment

⁷ Regulatory Research Associates. "Major Rate Case Decisions -- January - September 2009." October 2, 2009.

1 dollars—especially shareholder equity—were disallowed by state regulators through ex
2 *post* cost deliberations. It bears mention that Rhode Island regulatory policy has been
3 reasonably constructive regarding rate recovery over time.
4

5 **Q. What other challenges are utilities facing at the present time?**

6 A. The United States and, indeed, the world economies are currently in recession and
7 grappling with a very serious financial crisis. Although few industries are untouched by
8 these circumstances, utilities are particularly vulnerable because of their capital-intensive
9 nature and the magnitude of the construction expenditures they now face, a large portion
10 of which must be financed.
11

12 **Q. How is the financial crisis affecting the industry?**

13 A. As detailed in a white paper I prepared for the Edison Electric Institute earlier this year,
14 the financial crisis is affecting the industry in a number of ways.⁸ The capital markets,
15 while currently functioning, were in turmoil only a few months back. With the demise of
16 a number of investment and commercial banks, coupled with the significant weakening
17 of surviving institutions, access to capital was initially difficult for most companies and
18 impossible for others. Indeed, for a period of several weeks in September 2008, the debt
19 markets were completely closed to any company.
20

21 The financial markets themselves have been characterized by unprecedented volatility.
22 This has negatively affected the terms and cost of capital. Although some stability has

⁸ Julie M. Cannell, “The Financial Crisis and Its Impact on the Electric Utility Industry,” op.cit.

1 returned to the markets over the past few months, capital remains expensive relative to
2 recent years and its availability is potentially uncertain.

3
4 Utilities are significantly affected in this environment because of their need to raise
5 equity and debt to fund mounting construction programs. Companies have taken various
6 measures to ensure an adequate supply of capital. These measures have included deferral
7 of construction expenditures, drawing down existing lines of credit and pre-funding
8 capital requirements when windows of market opportunity open.

9
10 Despite their best efforts, utilities will continue to face uncertainty in the markets. With
11 fewer lenders now in existence, there is simply less capital available—a circumstance
12 which is expected to continue. Additionally, surviving institutions are imposing more
13 stringent lending standards. This has the effect of increasing competition for the capital
14 that is available, both within and beyond the utility sector. This circumstance increases
15 the risk for investors that some regulators will be unwilling to let utilities recover their
16 increased costs.

17
18 With the economy in recession and unemployment rates increasing, it is becoming more
19 difficult for companies and consumers alike to cope with rising prices. In particular,
20 utility companies are experiencing higher financing costs. These increased costs will
21 affect customers who need utility service, but are suffering their own financial hardships.
22 This increases the risk for investors because political and regulatory circumstances may
23 mean that utilities are unable to recover their increased costs.

1 **Q. What additional implications does the financial crisis hold for utilities?**

2 A. The current environment presents a distinct challenge to the industry. At a time when
3 utilities are starting major expansion initiatives, access to the capital markets has become
4 more questionable. As a result of the market shut down last fall, companies learned that
5 they could not count on being able to finance precisely on demand; rather, market access
6 was limited, volatile and very expensive. Although the markets are now open and the
7 cost of access has dropped from the crisis peak, participants are mindful that instability
8 could return again. Importantly, a utility's obligation to provide safe and reliable service
9 to customers remains firm regardless of market conditions. Companies must therefore be
10 proactive in their capital-raising efforts, seizing market opportunities when available.
11 Given the public-service obligation, it is imperative that the industry retain its financial
12 health and strength during this period of market uncertainty. This will require consistent
13 regulatory support. It will be imperative for electric utilities and regulators to
14 communicate effectively and work together to find the right balance in satisfying the
15 needs of all constituencies in this challenging environment. Maintaining a solid
16 regulatory compact will be critical.

17
18 **Q. Is the current economic recession a cause for concern among investors?**

19 A. Yes. Investors are both aware of the sensitivity of seeking an increase during a period of
20 economic hardship for some ratepayers and of a company's need to remain financially
21 viable during a time of major construction expenditures. As Wachovia noted in its
22 initiation report on Xcel Energy:

1 We are concerned that the poor economic environment could have an adverse
2 impact on XEL's ability to achieve outcomes as constructive as those in the past.
3 However, we believe the upheaval in the capital markets will make it difficult for
4 the Minnesota and Colorado public utility commissions to lack generosity, as a
5 harsh decision could materially hinder XEL's ability to make needed short- and
6 long-term investments in the system, risking reliability. In addition, the decline in
7 energy prices, particularly natural gas, has resulted in meaningfully lower fuel and
8 purchased power costs, providing some "cover" for the requested base rate
9 increases."⁹

10 Although the capital markets have regained some stability since the Wachovia report was
11 published, a new market "normal" has not yet been re-established and risk levels, as
12 previously discussed, remain high.

13
14 **Q. The Company is financially healthy company and has a strong credit rating.**

15 **Doesn't that guarantee it easy access in the credit markets?**

16 A. As previously discussed, the turmoil in the financial markets has resulted in no
17 company—no matter how financially strong—having carte blanche access to debt and
18 equity financing. The stronger the company, the better the odds that financing would be
19 available, but there are no guarantees.

20
21 **Q. In his direct testimony, Mr. Kahal suggested that the worst of the credit crisis**
22 **appears to have passed. However, you seem to be implying that problems may**
23 **persist with attendant implications for utilities. Please elaborate.**

24 A. As I noted, market access has improved in recent months as suggested by Mr. Kahal.
25 And, as he correctly observes, yield spreads have narrowed. That phenomenon, however,

⁹ Wachovia Securities. "Xcel Energy, Inc. XEL Coverage Initiated With An Outperform Rating; We View Environmental Leader As A Core Utility Holding." February 13, 2009.

1 is due more to investors trying to deploy capital as quickly as possible into assets where a
2 profit seems likely to exist, than to a change in risk perception. In fact, indications are
3 that many utilities will seek to pre-fund their 2010 capital requirements this fall, similar
4 to the path they pursued in late 2008 and early 2009 for the current year. This would
5 suggest that utilities are both seeking to secure financing when it is available and taking
6 advantage of current prices, which could become less attractive.

7
8 **Q. Haven't recent actions by the Federal Reserve signaled improving times ahead?**

9 A. Perhaps. Although the Federal Reserve's decision on August 12 to maintain the base
10 federal funds target rate at a record low due to the Board's belief that the economy and
11 markets are stabilizing was encouraging, the central bank also cautioned that recovery
12 would be slow. Markets rebounded strongly for several days, then retreated as worries
13 about further consumer retrenchment surfaced. Additionally, the Federal Reserve stated
14 that it would cease its program of Treasury bond purchases by October, which will
15 remove an important stabilizing feature from the markets.

16
17 **Q. Are there other factors present that could suggest more market volatility lies ahead?**

18 A. Yes. The Chicago Board Options Exchange Volatility Index ("VIX") is a widely
19 recognized measure of market volatility. Because investors value predictability, volatility
20 represents increased investment risk. When market volatility is high, investors require a
21 higher level of compensation for assuming that increased risk. Since its inception in
22 1990, the VIX's average level has been 20.25, which implies an average expected
23 volatility in the market of 20.25 percent. By contrast, during the height of the financial

1 crisis, the VIX Index exceeded 80, and the VXV (the 3-month volatility index)
2 approached 70, reflecting the unprecedented uncertainty that existed at the time.
3 Currently, the VXV is reflecting volatility of 27 percent. Although this represents a
4 significant decrease in volatility from the crisis peak, the number suggests prospective
5 average market volatility that is above historic norms, and thus, continued uncertainty
6 regarding the market.
7

8 **Q. Mr. Kahal's testimony¹⁰ refers to reports issued by Value Line discussing how both**
9 **gas and electric utility stocks have provided safe havens for investors over the past**
10 **year. Is this accurate?**

11 A. Mr. Kahal notes that Value Line opines that both electric and gas stocks "have been
12 increasingly sought after by investors over the past year." In the case of electric utilities,
13 Value Line attributes this phenomenon to "their relative stability and attractive dividend
14 yields." Value Line goes on to say, "All told, we believe this might be a good time to
15 increase your portfolio's electric-utility exposure." The measurement of stock
16 performance, of course, changes according to the period in question. Electric utility
17 stocks assuredly were desirable investments relative to those in other industry sectors
18 while the financial crisis was at its worst. But, as the markets began to improve last
19 spring, utilities became less sought after as investors sought out opportunities that might
20 be better leveraged to an economic recovery. Indeed, according to data provided by SNL
21 Energy (see Schedule NG-JMC-R-1), electric utilities, as measured by the S&P Electric
22 Utilities Index, declined 15.18 percent over the past year (through September 30, 2009)

¹⁰ Direct Testimony of Matthew I. Kahal on behalf of the Division of Public Utilities and Carriers, at 22-23.

1 compared to an 9.37 percent decrease for the broader market, as measured by the S&P
2 500. The key takeaway here is that electric stocks may have been safe havens during a
3 time of extreme economic distress, but they have failed to remain desirable investments
4 as a level of normalcy has returned to the markets and stocks in other industries have
5 offered more attractive returns. As noted previously in my testimony, there are
6 significant risks associated with electric utility investments, which is a dynamic
7 recognized by the market.
8

9 **Q. Please turn now to utility regulation. Why is the perception of regulatory climate of**
10 **such importance to investors?**

11 A. Equity investors today still seek companies that can offer stability in earnings and
12 dividends. Fixed-income investors look for stable and adequate cash flows to ensure
13 payment of principal and interest when due, as indicated by stable credit ratings. The
14 ability to pay dividends and sustain credit ratings is directly related to the consistency and
15 sufficiency of a utility's earnings, which depend in large part on how the utility is
16 regulated. If there is uncertainty about whether regulation will allow a utility the
17 opportunity to earn a reasonable return in future years, then that uncertainty will lead
18 investors to avoid holding investment positions in the utility, all other things being equal.
19 As a result, I believe that investors selecting electric utility stocks today place a very high
20 value on consistent and constructive regulation. And, with a new round of base rate case
21 filings underway in the industry, the quality of regulation is receiving renewed investor
22 attention.
23

1 **Q. In your experience as an analyst and portfolio manager, could a perceived change in**
2 **a company's regulatory climate affect your investment opinion?**

3 A. Absolutely. During my tenure as an institutional investor, a company's regulatory
4 environment was a critical factor in my assessment of its investment attractiveness. An
5 adverse regulatory decision could be a key determinant in my recommendation or
6 decision to sell a stock already owned or not to make an investment in one under
7 consideration.

8
9 **Q. Who are typical investors in utility stocks?**

10 A. There are two kinds of investors: individuals, who generally seek stability and income
11 from their utility holdings, and institutions, which generally seek total return (i.e., price
12 appreciation plus dividend income) from their utility investments.

13
14 **Q. How has the investment industry itself changed in recent years?**

15 A. In recent years, institutional investors and hedge funds have grown dramatically in the
16 amount of capital they control. This growth has had a significant impact on the speed
17 with which the market reacts to unfavorable developments. It has led the market to be
18 much more reactive and much less forgiving than it may have been in the past. In the
19 context of a regulatory decision, investors will not necessarily wait, as they would have in
20 the past, to see how the ramifications of a decision might play out. Rather, they simply
21 sell their shares if a regulator's decision runs counter to their expectations.

22
23 **Q. What has led to that change in the market's reaction?**

1 A. The market is now heavily populated by institutional investors, who play a significant
2 role in the marketplace.
3

4 **Q. Why are institutional investors of such importance generally?**

5 A. Because of the sheer size of their investment positions, institutions can effectively direct
6 the course of individual securities, and sometimes can move the market as a whole.
7 Institutional investors include financial institutions such as: mutual funds, investment
8 companies, insurance companies, commercial and investment banks, and various types of
9 public retirement funds. Institutional investors approach the investment selection process
10 from the standpoint of a portfolio. An investment portfolio is a collection of stocks
11 selected to achieve the highest possible return within a commensurate level of risk.
12 Therefore, institutional investors keep electric utilities in their portfolios only when such
13 stocks contribute to achieving the desired risk/return relationship.
14

15 It should be remembered that, generally, the customers of institutional investors are
16 individuals and it is they who ultimately gain or suffer loss from changes in the value of
17 the institution's investments. Anyone who has a stake in a retirement plan, owns a
18 mutual fund, or has a trust fund, for example, is directly or indirectly a client of an
19 institutional investor. But the individuals who make the decisions concerning these
20 investments are paid money managers, and how they see their responsibilities to the
21 clients they serve, and the way that their performance is judged, have a great deal to do
22 with how they react to developments in the market.
23

1 **Q. Why are institutional investors important to the Company and its parent National**
2 **Grid plc?**

3 A. Institutional investors warrant significant attention because they can dramatically change
4 the market for National Grid plc shares. Because institutional investors own large blocks
5 of shares relative to the volumes typically traded, their activity in moving in or out of the
6 company's shares is often noticeable as a significant change in the price and volume of
7 shares being traded for the company. This change may be picked up by other
8 institutional investors, by the investment community in general, and eventually by
9 individual investors. These other entities will then look to see what is driving this trend
10 in the stock and whether the trend is likely to continue or disappear. If they see support
11 for the trend, they may follow the lead of the firms that initially began to move the
12 market, and by following the leaders, the late movers may further strengthen the trend.

13
14 **Q. What does this mean for investments in regulated utilities specifically?**

15 A. This shortened time frame means that if there is bad news, institutional investors are
16 more likely to react quickly. In the instance of a rate proceeding, these investors are
17 unlikely to wait to see what the outcome of the next rate decision will be because there is
18 an opportunity cost associated with that strategy. Rather, institutional investors would be
19 more prone to sell their shares on the news of an adverse regulatory outcome. This
20 would not be good for customers either, for the reasons discussed earlier.

21
22 **Q. What role do credit agencies play in investors' expectations?**

1 A. In the wake of financial disasters, bankruptcies, and the ensuing severe erosion in
2 investor confidence in the past few years, credit issues have become critically important
3 not only to fixed income investors, but also to equity investors. Although credit
4 downgrades initially impacted only the most troubled companies, a spillover effect soon
5 was experienced by healthy utilities. Part of this was due to the fact that the rating
6 agencies came under harsh criticism that they had failed to detect problems early enough
7 in companies such as Enron Corp. As a result, ratings agencies began to heighten their
8 scrutiny of all entities under their watch and became far more proactive in making rating
9 changes. As well, “headline risk” began to come into play, as investors worried that –
10 when credit problems in an industry are in the headlines—any company in the sector
11 could be vulnerable to a downgrade. Thus, equity investors now closely watch the
12 actions of the credit agencies, because any change in ratings can signal underlying
13 problems and have a significant impact on a company’s stock price.

14
15 **Q. What happens when a credit downgrade occurs?**

16 A. In the simplest terms, it becomes more expensive for a company to raise money in the
17 capital markets because a downgrade raises a company’s risk profile and consequently,
18 increases the cost of debt. And because of the increased linkage these days between
19 negative events and stock prices, the stock price frequently reacts—sometimes quite
20 strongly—to a downgrade. It should be noted that both negative and positive changes in
21 credit ratings can and do occur as a result of regulatory actions.

III. INVESTORS' PERCEPTIONS OF THE CURRENT PROCEEDING

Q. How have you gauged investors' perceptions of the issues in this proceeding?

A. To supplement my own knowledge of the industry, I have reviewed various reports related to the Company and its parent National Grid plc written by investment analysts. A clear picture of investor perceptions emerges from these reports, which is in keeping with my own views.

Q. Which credit agency reports have you examined?

A. I have examined reports written by Moody's and S&P, which are the two key credit rating agencies.

Q. What exactly is a credit rating?

A. A credit rating is the assessment by the credit rating agencies of a company's ability to pay its fixed income obligations on time and in full. Each of the agencies makes these evaluations according to a tiered scale, with 'AAA' being the highest credit and 'D' or 'C' indicating the lowest, or default. Ratings of 'BB+' (S&P) or Ba1 (Moody's) or lower are indicative of non-investment grade credits.

Q. How do the agencies currently rate the Company?

A. The Company's ratings are as follows:

	<u>Rating</u>	<u>Outlook</u>
Moody's	A3	Stable
S&P	A-	Stable

1 **Q. Why is having an investment-grade credit rating important?**

2 A. In simple terms, the higher the credit rating, the less it costs to borrow. In turn, lower
3 borrowing costs translate into lower customer rates. But on a slightly more complex
4 level, when a debt rating nears or enters non-investment grade or “junk” status, interest
5 costs begin to rise significantly because lenders need a higher return as compensation for
6 the much higher risk they are incurring. It bears mention that credit rating downgrades
7 occur more readily than do upgrades. Further, when a credit rating is officially non-
8 investment grade, many financial institutions are no longer permitted to hold the bonds of
9 the company in question. That company’s debt is considered to be unsafe and thus unfit
10 for inclusion in conservative investment portfolios.

11
12 **Q. Why is a utility’s regulatory environment important to the rating agencies?**

13 A. The rating agencies appraise companies on the basis of creditworthiness. Rating agencies
14 also evaluate current financial soundness and attempt to discern how that might change in
15 the future. One of the key factors in assessing a utility’s financial picture is the
16 regulatory climate in which the company operates, because regulators influence the
17 utility’s capital structure and establish allowed returns that may be earned on that capital.
18 Thus, a regulatory environment characterized by consistency and predictability is one that
19 lends itself to a company’s having a sounder financial base. Conversely, a regulatory
20 situation defined by a lack of stability can have a deleterious impact on a utility’s credit
21 profile.

1 **Q. Have the agencies quantified the extent to which they consider regulation in their**
2 **ratings process?**

3 A. In an update to the ratings methodology it has followed since 2005, Moody's recently
4 provided additional transparency to its process.¹¹ The firm identified the key factors it
5 examines in its ratings and quantified them. Regulation is clearly of paramount
6 importance: "regulatory framework" and "ability to recover costs and earn returns" each
7 carry a 25 percent weighting. The other ratings factors are diversification (10 percent)
8 and financial strength and liquidity (40 percent).

9
10 **Q. Does Moody's explain the rationale behind its designation of key factors and the**
11 **weighting of those factors?**

12 A. Yes. The agency explains the import behind and measurement of each factor.
13

14 **Q. Please elaborate on Moody's views regarding "regulatory framework."**

15 A. Moody's notes that "the predictability and supportiveness of the regulatory framework"
16 in which a utility operates is a "key credit consideration." The agency said it examines
17 various factors of a regulatory environment, including "how developed the regulatory
18 framework is; its track record for predictability and stability in terms of decision making;
19 and the strength of the regulator's authority over utility regulatory issues. A utility
20 operating in a stable, reliable, and highly predictable regulatory environment will be

¹¹ Moody's Electric Service, "Rating Methodology: Regulated Electric and Gas Utilities." August 2009.

1 scored higher on this factor than a utility operating in a regulatory environment that
2 exhibits a high degree of uncertainty or unpredictability.”¹²

3
4 **Q. What about the second regulation-related factor, “ability to recover costs and earn**
5 **returns”?**

6 A. Moody’s states “the ability to recover prudently incurred costs in a timely manner is
7 perhaps the single most important credit consideration for regulated utilities, as the lack
8 of timely recovery of such costs has caused financial stress for utilities on several
9 occasions.” The agency pointed to the fact that regulatory disputes which ended in
10 insufficient or delayed rate relief were a factor in 4 of the 6 major investor-owned utility
11 bankruptcies in the U.S. over the last 50 years. Moody’s also opined that “currently, the
12 utility industry’s sizeable capital expenditure requirements for infrastructure needs will
13 create a growing and ongoing need for rate relief for recovery of these expenditures at a
14 time when the global economy has slowed.”¹³

15
16 **Q. How do the rating agencies view the Company and its regulatory environment?**

17 A. Both agencies have a generally positive view of the Rhode Island regulatory environment
18 in which the Company operates. S&P notes:

¹² Ibid.

¹³ Ibid.

1 The regulatory agreement between the Rhode Island Public Utility
2 Commission and Narragansett Electric is generally supportive of credit
3 quality, because it allows for the recovery of all costs incurred as the
4 provider of last resort, although with some delay, insulating the company
5 from exposure to commodity prices.¹⁴

6
7 Moody's, in discussing the Company's rating considerations stated:

8 Our assessment also assigns significant weighting to the fact that Rhode
9 Island is one of the more predictable and supportive regimes in the US on
10 the regulatory spectrum.¹⁵

11
12 **Q. Have the agencies expressed any expectations about the Company's regulatory**
13 **situation?**

14 A. Yes. Moody's, shortly before releasing its ratings methodology paper, changed the
15 ratings outlook of parent National Grid plc and its subsidiaries from "negative" to
16 "stable." In the context of that action, Moody's voiced its expectations that the U.S.
17 subsidiaries will see improved earned returns as a result of rate proceedings, and
18 simultaneously issued a warning if that turns out not to be the case:

19 Moody's has also taken into account the anticipated financial strategies
20 and pending rate case filings for National Grid's US subsidiaries and the
21 further rate cases that are expected to be filed in the next 15 months
22 (covering more than 50% of the US rate base). Moody's places significant
23 weight upon its expectation that these filings will increase authorized
24 returns as well as improve earnings and cash flow through FY2010/11 for
25 National Grid's US operations and the group as a whole.

26
27 Moody's anticipates that National Grid will exceed the minimum credit
28 metrics set forth in FY2009/10, but believes that FY2010/11 may be
29 challenging. Low inflation/deflation will reduce allowed revenue for the
30 regulated UK businesses, whilst any subsequent spike in inflation could
31 push up interest and other costs. If the expected increase in achieved
32 returns for the US businesses fails to materialize, then downward pressure

¹⁴ Standard & Poor's Corporation. "Narragansett Electric Co." September 24, 2009.

¹⁵ Moody's Investors Service. "Credit Opinion: Narragansett Electric Company." March 23, 2009.

1 on the consolidated key credit metrics could result and they may again fail
2 to meet the minimum levels needed to maintain the current ratings.¹⁶
3

4 **Q. What is S&P's viewpoint?**

5 A. The credit rating agency recently made mention of the Company's pending \$75.3 million
6 rate case. Additionally, and similar to Moody's, S&P stressed the importance of
7 supportive regulatory outcomes in all the National Grid USA filings so as to maintain
8 credit quality:

9 Generally, the various regulatory jurisdictions have been reasonably
10 supportive of creditworthiness, but during the company's accelerating
11 capital expenditure phase, sustained support is especially important. The
12 commissions, however, will be reviewing prospective rate requests at a
13 time of unusual economic hardship, so the subsidiaries' ability to manage
14 regulatory risk will be critical to credit quality.¹⁷
15

16 **Q. What conclusions do you draw from the credit-rating agencies' assessments of the**
17 **Company and its regulatory environment?**

18 A. Both S&P and Moody's have a constructive opinion of Rhode Island regulation. That
19 view, however, is based on the Commission's historical practices, and this is the first
20 fully litigated base-rate proceeding the Company has had since 1995. S&P stated that
21 sustained regulatory support, even during the current challenging economic environment,
22 would be critical to credit quality. Moody's expressed its strong expectation that the
23 outcome of the current proceeding (as part of a group of rate cases in which National
24 Grid U.S. subsidiaries are or will be engaged) will result in improved earned returns. The
25 agency issued the caution that a continuation of subpar returns could result in metrics

¹⁶ Moody's Investors Service. "Rating Action: Narragansett Electric Company. Moody's Changes National Grid's Outlook to Stable." July 20, 2009.

¹⁷ Standard & Poor's, op.cit.

1 insufficient to maintain the current ratings, which raises the possibility of a downgrade.
2 Further, Moody's recent quantification of key ratings factors—in which regulatory
3 climate and the ability to recover costs and earn a return comprise 50 percent of the total
4 assessment—emphasized the importance of the regulatory environment in the ratings
5 process. Clearly, Moody's (and presumably S&P, as well) will be closely attuned to the
6 outcome of the current rate case.
7

8 **Q. Beyond the view of the credit-rating agencies, has other opinion been offered on**
9 **Rhode Island regulation?**

10 A. Yes. Regulatory Research Associates (RRA) has ranked the Commission from an
11 investor perspective. In its most recent quarterly evaluation of state regulatory
12 commissions, RRA accorded Rhode Island regulation an "Average-2" rating.¹⁸ There are
13 three tiers to RRA's ranking scheme: Above Average, Average, and Below Average,
14 with a numeric designation of 1, 2, or 3 (1 representing the strongest) within the principal
15 rating category employed to indicate relative strength therein. The regulatory firm notes
16 that its evaluations "are assigned from an investor perspective and indicate the relative
17 regulatory risk associated with the ownership of securities issued by the jurisdiction's
18 electric, gas, and telephone utilities. Each evaluation is based upon our studies of the
19 numerous factors affecting the regulatory process in the state, and is changed as major

¹⁸ Regulatory Research Associates. "State Regulatory Evaluations." July 15, 2009.

1 events occur that cause us to modify our view of the regulatory risk accruing to the
2 ownership of utility securities in that individual jurisdiction.”¹⁹

3 In its profile of the Commission, RRA stated:

4 The regulatory climate in Rhode Island has historically been, and
5 continues to be, relatively balanced from an investor viewpoint. There
6 have been relatively few rate case decisions in recent years. Historically,
7 however, equity returns have approximated industry averages. . .
8 Alternative regulation plans are in effect for the electric and gas operations
9 of Narragansett Electric that provide for graduated earnings sharing above
10 the benchmark returns. . . We continue to accord Rhode Island regulation
11 an Average/2 rating.²⁰
12

13 **Q. Are there additional inferences to be drawn from investors’ views of regulation?**

14 A. Yes. One of the key factors analysts use to evaluate the quality of a regulatory climate is
15 the consistency of a commission’s decisions. Investors value certainty and predictability,
16 and therefore, a lack of consistency in a commission’s actions or decisions serves to
17 increase the investment risk associated with a utility. With an unpredictable track record
18 of regulatory decisions and actions, investors are unable to anticipate reliably the future
19 actions of a commission. That in turn depresses valuations—i.e., lowers the price of a
20 stock and increases a company’s cost of borrowing. In a study I prepared in 2005 for the
21 Edison Electric Institute on investor perceptions of state regulation, respondents were
22 asked to cite the regulatory factors they felt characterized a constructive environment, as
23 well as a non-constructive environment. On the positive side of the ledger, one of the top
24 set of factors was a regulatory climate that is “fair, stable, predictable, and consistent.”
25 The top factor cited by the respondents as characterizing a non-constructive environment

¹⁹ Ibid.

²⁰ Regulatory Research Associates. “State of R.I. Public Utilities Commission.” Quoted section updated 9/21/09.

1 was a climate that is “arbitrary, inconsistent, and unwilling to acknowledge the economic
2 realities that utilities face.” One investor summed up that type of non-constructive
3 regulation as “regulatory purgatory.”²¹

4
5 **Q. What bearing does the investor opinion regarding regulation you’ve referenced**
6 **have on the current proceeding?**

7 A. Investors have a reasonably constructive opinion of Rhode Island regulation. One of the
8 factors that analysts value most in assessing a potential investment is consistently and
9 predictability; the state regulatory perception study I conducted for the Edison Electric
10 Institute confirmed that fact.

11
12 This is a precarious time for the electric utility industry. With companies (including the
13 Company) facing soaring costs of construction, environmental compliance and other
14 activities, and also requiring reasonable access to the capital markets to fund those
15 requirements, supportive regulation is critical. Historically, the Commission has found a
16 consistent balance of customer-oriented policies and supportive ratemaking policies,
17 leading investors to expect a continuation of a constructive regulatory environment in the
18 state prospectively.

19
20 **Q. Turn now, please, to the viewpoint of equity investors and their opinion of the**
21 **Company and its regulatory situation.**

²¹ J.M. Cannell, Inc., “State Utility Regulation: An Assessment of Investor Perceptions,” August 2005.

1 A. Because the Company's parent, National Grid plc, is a British corporation, its stock is
2 analyzed by a number of investment firms based in the United Kingdom. Part of that
3 analysis entails an examination of the fundamentals of U.S. operations. As evidenced in
4 the following observation from brokerage firm Charles Stanley, there is a keen
5 understanding among investors that the U.S. businesses have been underperforming.

6 The performance of National Grid's US businesses was disappointing in
7 2008-09 with achieved return on equity dropping to 8.4%, from 9.4%, and
8 over 200 bp below allowed regulatory returns.²²
9

10 Credit Suisse echoed the same view:

11 While NG is meeting regulatory allowed returns in the UK, some of its US
12 regulated businesses are collectively underperforming their allowed return
13 on equity. The underlying problem is that US rate plans have aged and
14 costs have increased. Using numbers presented by NG, the US businesses
15 appear to be underperforming net income by cUS\$125M (£76m, or
16 c3.1p/share).²³
17

18 **Q. Is there an awareness of the parent's U.S. regulatory agenda?**

19 A. Definitely. National Grid's rate-case plans constitute an important factor in the
20 investment case for the stock, as explained in a Goldman Sachs report.

21 NG continues to progress a busy regulatory agenda in the US (over the
22 next 15 months, rate cases are expected to be filed covering more than
23 50% of US rate base). ... All filings have the aim of achieving timely
24 recovery of costs, pension and benefit true-ups, bad debt recovery,
25 decoupling, investment and competitive returns. By 2011, NG targets a
26 double-digit return across the whole of the US rate base.²⁴
27

28 Deutsche Bank provided similar commentary:

²² Charles Stanley. "National Grid." July 27, 2009.

²³ Credit Suisse. "National Grid: a little too early to buy." July 21, 2009.

²⁴ Goldman Sachs. "National Grid: Return Potential: 4%; US delivery expected; overvalued relative to sector: Conviction Sell." July 17, 2009.

Tackling returns & regulatory architecture in the US

National Grid is now firmly targeting achieved return in its US business. It will be undertaking a programme over the next couple of years of seeking revised rate cases in many of its key regulatory jurisdictions, seeking to restore RoEs to acceptable levels and improve the feature of the regulatory formulas to provide enhanced incentives and reduce risk.²⁵

Q. Has investor attention been paid to the current proceeding in Rhode Island?

A. Yes, although the commentary has been fairly general. For example, Goldman Sachs noted:

Electric rate cases have been filed in Massachusetts and Rhode Island. A decision in Massachusetts is expected by the end of the year with Rhode Island coming in early next year. NG says that the filings will benefit both customers and shareholders by supporting much needed investment and full recovery of costs.²⁶

Nomura International also referenced the filing:

The real inflection point on the US comes with the upcoming rate cases for Massachusetts electricity (10% of US rate base), Rhode Island electricity (4%) and NiMo electricity (24%). Rate cases for both Massachusetts and Rhode Island have already been filed, with a result expected towards the end of the year that will help increase achieved returns up from 7% and 2.3% of last year; it is important to note that a true up of costs, no matter what the headline return, is likely to lead to improved profitability in these regions given the low starting point.²⁷

Q. What expectations do equity investors have for U.S. rate relief?

A. Although there are no published projections of the case outcomes in terms of revenues or returns, there is clearly a belief that adequate rate relief will be forthcoming to improve earned returns, support credit ratings, and justify current investment valuations. This is

²⁵ Deutsche Bank. "National Grid PLC: Forecast & Valuation Update." May 29, 2009.

²⁶ Goldman Sachs, op. cit.

²⁷ Nomura International. "National Grid: Time to Break the Grid lock." July 9, 2009.

1 captured in a heading within the previously referenced report by Goldman Sachs:
2 “Downside risk in shares if US profitability is not improved.”²⁸ Several investment
3 reports published when Moody’s changed the ratings outlook for National Grid plc and
4 its subsidiaries also emphasized the agency’s expectation that regulatory outcomes will
5 support credit metrics necessary to maintain current ratings.

6
7 **Q. Has there been any recent commentary from equity investors about National Grid’s**
8 **U.S. regulatory effort?**

9 A. Yes. Last month, Morgan Stanley wrote extensively on its expectations that U.S. rate
10 relief would be successful in producing improved returns.

11 **National Grid should improve its US returns.** Two-thirds of NG’s US
12 businesses earn returns below acceptable levels, and well below the
13 returns allowed by the state regulators. To improve these returns, NG is
14 seeking rate cases to improve tariffs. The early evidence is promising.
15 The US management team, revamped over the last two years, is starting to
16 have a positive effect.

17 - - - - -

18 Another interesting attraction of NG is the “free option” that we believe
19 the current share price offers on a recovery of profitability in its US
20 business. This recovery will be driven by successful regulatory rate cases.
21 In our view, NG has started to show that it can be successful in this area.
22 While regulatory outcomes are never certain, we think some precedent,
23 and a track record of success from the new US management team is
24 starting to emerge.

25 - - - - -

26 The next rate case decisions are due in late 2009 in the states of
27 Massachusetts and Rhode Island. Success here will be sufficient to give
28 us confidence that the recovery will be achieved.

29 - - - - -

30 NG is now in the process of fixing its returns, by filing for new rates in all
31 of its jurisdictions. In our view, this business will be “fixed” and if this is
32 not possible, NG will seek to maximize value for shareholders in other

²⁸ Goldman Sachs, op. cit.

ways. In a number of small rate cases, NG has achieved satisfactory allowed returns, well in excess of the current earned ROE.²⁹

Q. Did Morgan Stanley express any expectations for the allowed ROE level in the current proceeding?

A. Not specifically. The firm did, however, state a 10.5 percent target ROE assumption for all the National Grid US subsidiaries:

Put another way, if NG gets to a 10.5% achieved ROE in all of the US businesses in which it is currently under-earning, we believe this could increase EPS by 9p or 16%.³⁰

Q. Do investors see risk in the Company's regulatory situation?

A. Despite the expectation that returns for the Company and the other National Grid USA subsidiaries will improve as a result of rate relief, concern is evident. As Deutsche Bank noted, "With five + rate cases to pursue over the next few years, the main risk for National Grid is US regulation."³¹ Citi addressed the risk element from a different standpoint:

US businesses – achieved ROEs are now well below the allowed levels for 67% of US asset base. NG should receive a revenue boost (up to \$400m pa.) as this gap is closed. But the poor returns do demonstrate how challenging the US regulatory environment is, and question [markets: sic] marks remain as to whether NG creates value from its US operations.³²

More recently, Citi wrote:

²⁹ Morgan Stanley. "National Grid: Defensive attractions with free option on US recovery." September 10, 2009.

³⁰ Ibid.

³¹ Deutsche Bank. "National Grid PLC: Credit Rating Confirmed." July 20, 2009.

³² Citi. National Grid PLC: NG seeks to quash financing worries." May 14, 2009.

1 NG remains optimistic that US rate filing [sic] will deliver the revenue
2 increases required to provide appropriate returns. But it is a slow and
3 complex process. NG would consider selling any US businesses where it
4 was not possible to achieve satisfactory returns³³
5

6 Similar commentary was provided by Morgan Stanley:

7 If the US business does improve its returns materially, we think this would
8 lead to a re-rating of NG's shares. And as a "back-stop," we believe that
9 if NG cannot successfully deliver improved returns in the US, it would
10 seek to exit the business.³⁴
11

12 **Q. Please elaborate on Citi's and Morgan Stanley's respective observations.**

13 A. While implying that constructive rate treatment would serve to bolster returns back up to
14 allowed levels in National Grid's U.S. utility operations, Citi pointed to the subpar
15 returns as testament to the challenging nature of U.S. regulation. More importantly, the
16 brokerage firm raised the issue of whether parent National Grid plc is receiving adequate
17 value from its American subsidiaries. The tacit suggestion appears to be that a
18 continuation of inadequate return levels could result in National Grid's deciding to
19 deploy its capital elsewhere, either by shifting overall investment more heavily toward
20 the U.K. or by divesting its U.S. properties. Morgan Stanley overtly stated that it
21 envisions a divestment of US operations by National Grid plc if returns in utility
22 operations here do not improve. Just a few years ago, ScottishPower, unable to realize
23 acceptable returns in its investment in PacifiCorp, chose to sell the multi-state utility
24 property to MidAmerican Energy Holdings.
25

³³ Citi. European Utilities Daily. "National Grid: National Grid Presentation Feedback." August 7, 2009.

³⁴ Morgan Stanley, op.cit.

1 **Q. Please summarize equity investors' views of the Company and its regulatory**
2 **situation.**

3 A. Investors are well aware that the Company and the other U.S. utility subsidiaries have
4 been substantially underearning their allowed return levels. Investors widely anticipate
5 this predicament to be remedied through the proceeding now underway in Rhode Island,
6 as well as through rate cases in other jurisdictions. Despite this expectation, however,
7 there is a recognition that risk of a subpar outcome exists, which could result in an
8 undermining of the basic investment case for National Grid plc stock, the possibility of a
9 credit downgrade, and/or a change in the parent's financial support for its subsidiaries.

10
11 **IV. RETURN ON EQUITY IN THIS PROCEEDING**

12 **Q. Please comment on Mr. Kahal's ROE recommendation.**

13 A. Although the Division's recommended ROE is a positive step in this proceeding, I do not
14 believe Mr. Kahal's proposed 10.1 percent ROE is consistent with investor expectations
15 for the Company. The Company is in a period of rising construction expenditures and the
16 regulatory lag associated with the ratemaking process (even where capital additions are
17 included through the end of the rate year) creates regulatory uncertainty and investor
18 wariness. As noted previously in my testimony, risks are increasing for utilities and
19 investors will need to be compensated for that increased risk. In the 35 case decisions
20 rendered over the past year, there have been only six ROE allowances as low as or equal
21 to 10.1 percent nationwide since the onset of the financial crisis and recession last fall.
22 Of those six cases, one involved an order that "followed partial stipulation or settlement
23 by the parties. Decision particulars not necessarily precedent setting or specifically

1 adopted by the regulatory body,” according to RRA. The return parameters in another
2 order pertained only to a utility’s ownership in a specific generating plant. In a third
3 case, the ROE related to a proposed coal plant. So, in essence, only three of 35 relevant
4 ROE decisions rendered over the past year have been as low as or equal to the 10.1
5 percent proposed by Mr. Kahal. These factors taken together suggest that Mr. Kahal’s
6 recommendation would not meet investor expectations for the Company.

7
8 **Q. You mentioned that Morgan Stanley is targeting a 10.5 percent ROE for all**
9 **National Grid’s U.S. subsidiaries. Do you believe that an authorized ROE of 10.5**
10 **percent is sufficient to comport with investor expectations?**

11 A. No. Morgan Stanley’s target is for a 10.5 percent achieved return at the U.S. utilities.
12 Although the test year in this rate proceeding is more forward-looking than a straight,
13 historic test-year approach, the regulatory lag associated with the ratemaking process, the
14 need for significant ramp up of infrastructure replacement, continuing operating cost
15 increases, and revenue loss associated with significant increases in energy efficiency to
16 help customers manage their total electric bill, will all contribute to the Company’s
17 having substantial difficulty in achieving the rate of return authorized in this proceeding.
18 My experience tells me that Morgan Stanley likely assumed a 10.5 percent earned return
19 level in recognition of the fact that higher allowed returns are required to achieve that
20 earned ROE.

21
22 **Q. Why do return on equity rewards vary among state commissions and companies?**

1 A. As Mr. Moul's direct testimony sets forth, generic factors such as interest rates and
2 industry issues contribute to a determination of return on equity, but in the final analysis,
3 the appropriate ROE level is specific to the company in question. For example, as noted
4 previously, the Company has a number of risk factors relevant to a wires-only utility that
5 increase its risk, coupled with company-specific issues, such as its major capital
6 expansion program, which should argue for a higher allowed ROE as compensation for
7 that greater risk level.

8
9 **Q. You mentioned previously that investors have not published specific expectations**
10 **for the current proceeding in terms of return levels. Can you point to other**
11 **examples of rate cases in which allowed ROEs either met or disappointed investor**
12 **expectations?**

13 A. Yes. The ruling in February 2009 by the Connecticut Commission of Public Utility
14 Control in a United Illuminating rate case serves as a powerful example of investor
15 disappointment. Not only was the company granted only a fraction of its request (though
16 trackers for pension and other expenses were provided, as was revenue decoupling), but it
17 also—and most importantly—was permitted only an 8.75 percent ROE, the lowest level
18 allowed any electric utility in the country over the past 30-plus years. Investor response
19 to this development was swift and brutal. Between February 3, the day before the
20 regulators' ruling and March 9, 2009, when the stock finally reached a nadir, the price of
21 UIL Holdings (the utility's parent) declined by 37 percent. That enormous loss of
22 shareholder value stands as a vivid testament that the regulators' ruling did not meet
23 investor expectations.

1 A more positive example involves Tampa Electric. In mid-March, the Florida Public
2 Service Commission, both weighing “witnesses’ models against the level of currently
3 authorized returns around the country” and “taking into account the utility’s proposed
4 construction program and its need to access the capital markets during this potentially
5 challenging period,”³⁵ granted the company an 11.25 percent ROE, the midpoint of a
6 10.25 percent to 12.25 percent range, as compared to the company’s 12.0 percent request.
7 The fact that the PSC affirmed the utility’s assertion that it needed a reasonable allowed
8 return level to ensure sufficient financial health to provide access to the financial markets
9 prompted the stock of parent TECO Energy to climb 35 percent in the roughly 2-week
10 period between the Commission Staff’s recommendation and the final order. Clearly, the
11 outcome of this rate proceeding was consistent with investors’ expectations.

12
13 **Q. Please comment on Mr. Moul’s ROE recommendation.**

14 A. Mr. Moul notes that the fair and reasonable cost of equity capital for the Company is 11.6
15 percent. Investment risk in the electric utility industry is rising, and investors are
16 requiring greater levels of compensation to assume that added risk. As an input in
17 valuation models, earnings levels logically translate into the attractiveness of a stock,
18 other factors being equal. A reasonable ROE allowance should help bolster the
19 Company’s financial health, earnings power, and, accordingly, equity investment
20 valuations of its parent. A reasonable allowed ROE level should also help ensure that
21 current credit ratings are not jeopardized.

22

³⁵Florida PSC, Order No. PSC-09-0283-FOF-EI, Docket No. 080317-EI.

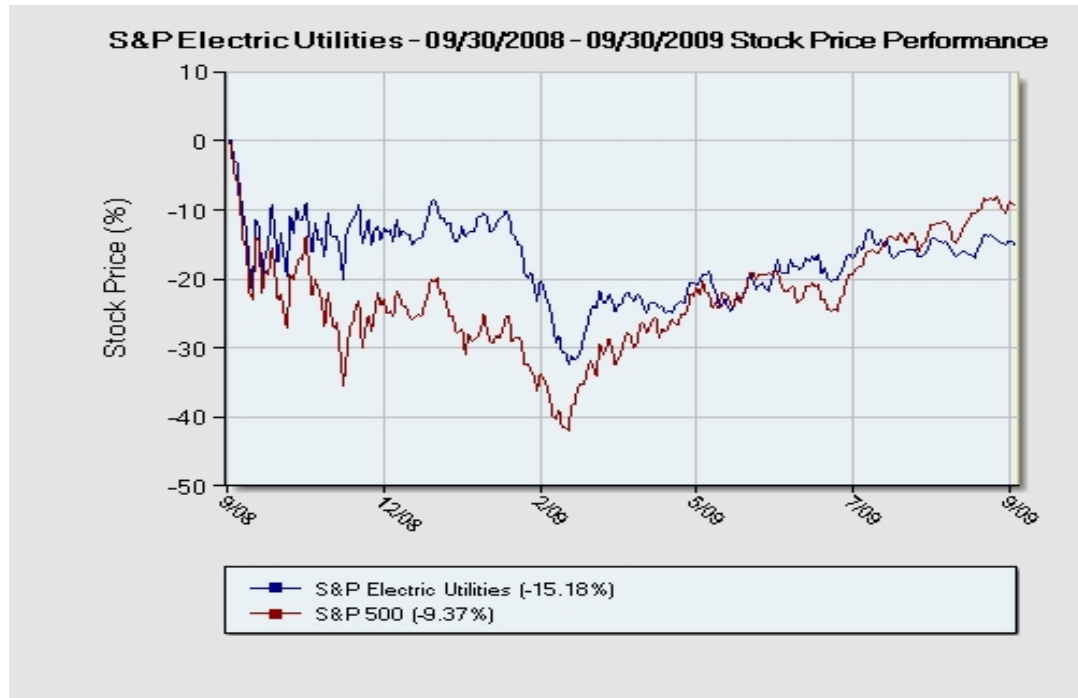
1 **Q. Could a return on equity award that is consistent with investor expectations also be**
2 **expected to provide benefits to the Company's customers?**

3 A. Absolutely. A higher ROE permits the realization of a stronger earnings stream. In turn,
4 that can improve a company's stock's valuation prospects, which results in a higher stock
5 price. Thus, when a company needs to enter the equity markets for capital required to
6 meet customer needs, it can get more for its money. Said another way, each share sold
7 brings more equity into a company with the same commitment by the company to
8 generate earnings and pay dividends to support the value of that share. With respect to
9 debt financing, a higher ROE awarded to the Company would be viewed as a sign of
10 constructive regulation and would be positive for the Company's credit rating, since
11 strengthened financial metrics would help support the existing credit ratings, which
12 would ultimately produce a relatively lower cost of capital for customers.

13
14 **Q. Does this conclude your testimony?**

15 A. Yes.

Market Data Graph



REBUTTAL TESTIMONY

OF

WILLIAM F. DOWD

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1 **I. Introduction and Purpose of Testimony**

2 **Q. Please state your name and business address.**

3 A. My name is William F. Dowd. My business address is 40 Sylvan Road, Waltham, MA
4 02451.

6 **Q. Did you previously submit pre-filed testimony in this proceeding?**

7 A. Yes. I submitted pre-filed direct testimony on June 1, 2009.

9 **Q. What is the purpose of your rebuttal testimony?**

10 A. The purpose of my rebuttal testimony is to address recommendations put forth in this
11 proceeding by the Division of Public Utilities and Carriers (the “Division”) through the
12 Direct Testimony of Mr. David J. Effron. In particular, my rebuttal relates to the
13 Division’s recommendations on variable pay and union labor commitments.

15 **II. Variable Pay**

16 **Q. The Division takes the position that 50 percent of the variable-pay compensation**
17 **paid to employees of National Grid should be excluded from the test-year adjusted**
18 **cost of service based on the theory that compensation paid to employees in relation**
19 **to the attainment of financial goals, such as earnings or return on equity, should not**
20 **be recoverable from customers. Do you agree?**

21 A. No. As I will explain below, the Division’s recommendation to disallow \$1,204,000 in
22 employee-compensation expenses from the adjusted test-year cost of service should not
23 be accepted by the Commission. “Incentive compensation,” or variable pay, is an
24 integral component of an employee’s *total compensation*, with an employee’s total

1 compensation set at levels that are designed to be competitive with levels offered by other
2 employers so that the Company is able to attract and retain qualified employees to
3 operate the distribution system. As a result, disallowance of the variable pay component
4 has ramifications that should be considered by the Commission in assessing the
5 Division's recommendations to disallow variable pay.
6

7 **Q. Would you discuss how variable pay factors into an employee's total compensation**
8 **level?**

9 A. Yes. As I explained in my direct testimony, National Grid's approach to setting
10 employee compensation is to use a combination of base and variable pay in order to
11 strengthen the link between compensation and the achievement of designated
12 performance objectives. The Company strongly believes that the incorporation of
13 performance objectives should be an approach that is considered by public utility
14 regulators to be in the public interest given that the Company needs to pay competitive,
15 market-based compensation in order to attract and retain qualified employees in any
16 event, and therefore, the incorporation of performance-based pay provides an incremental
17 benefit to customers as compared to a 100 percent base-pay structure. In fact, the use of
18 a base/variable-pay structure has become prevalent throughout the electric distribution
19 industry, as well as competitive industries with nearly 100 percent of companies of
20 National Grid's size having variable-pay plans in place, and over 90 percent of
21 employees at those companies participating in those plans (see Schedule NG-WFD-6, at
22 6). Thus, National Grid designs total compensation levels, including the variable-pay
23 component so that (1) employees' total compensation is reasonable after considering base
24 and variable pay *on an aggregated basis*, (2) variable pay is based on both the overall

1 performance of the company and the performance of the individual, and (3) individual
2 performance goals are designed to achieve specific service-related objectives that are key
3 to providing safe, reliable and reasonable cost service to customers.
4

5 Although the Division's recommendation is aimed at eliminating only that portion of
6 variable pay that is related to financial goals, the Company's perspective is that the
7 incorporation of financial goals for the vast majority of employees is inextricably tied to
8 the achievement of customer-service goals. This is because, for these employees,
9 financial goals are the Company's *tool for measuring* the success of "grass roots,"
10 enterprise-wide efforts to operate safely, contain operating costs and to structure
11 operations in a way that is efficient and effective in providing service to customers. In
12 practice, the Company cannot meet its financial goals without employees at all levels
13 achieving the "customer-oriented" goals that are referenced in Mr. Effron's testimony as
14 being acceptable objectives for recovery through rates. Therefore, for these employees,
15 financial goals serve as a metric for gauging the success of employee performance on
16 customer-service goals, which is the reason that an individual's variable pay is not fairly
17 disaggregated for ratemaking purposes between "shareholder-oriented goals" and
18 "customer-oriented goals." Structuring compensation in this manner is inherently
19 beneficial to customers because it produces customer benefits across the organization (in
20 the form of safety, cost-containment, reliability and service quality) more effectively than
21 the traditional approach of using bonuses on top of base compensation, which is set at the
22 market-competitive level and paid to the employee without specific performance metrics
23 in place.
24

1 Lastly, I would point out that, the Division's recommendations do not make note of the
2 fact that the Company's revenue requirement in this case does not include the variable-
3 pay component for National Grid's Band A executives (National Grid's most senior
4 executives). Excluding variable pay for Band B through F employees (which consist of
5 senior vice presidents through associate analysts), will only put the Company at a
6 competitive disadvantage in terms of attracting and retaining those employees in the
7 future.

8 **Q. Would you provide more explanation as to the ramifications for employee**
9 **compensation levels if variable pay is not allowed by the Commission?**

10 A. Yes. As I have tried to convey above, variable pay is part of an employee's total
11 compensation level. Therefore, when the employee accepts a position with National
12 Grid, or considers alternative employment opportunities in the marketplace, the employee
13 will be evaluating his or her total compensation level against the compensation offered in
14 the marketplace. If National Grid were to compensate its employees only with the level
15 of base pay provided for under the current compensation program (i.e., at the level paid to
16 employees exclusive of some or all of variable-pay component), its compensation levels
17 would be lower than compensation available from similar employment opportunities in
18 the marketplace. Over time, National Grid would be unable to attract and retain the type
19 of qualified employees needed to conduct its operations. This effect would impair the
20 Company's ability to operate safely, reliably and efficiently and is directly contrary to the
21 interests of customers. Thus, to counteract this effect, the Company would need to *raise*
22 *base pay levels* to achieve total compensation levels that are commensurate with levels
23 available to qualified employees in the marketplace, which simply returns to a model

1 where total compensation is paid wholly on the basis of *employment* rather than on the
2 basis of *performance*. The Company fundamentally believes that (1) the use of base and
3 variable pay components to set total compensation, and (2) the use of financial goals
4 within the variable-pay structure to incentivize individual employee performance on
5 customer-service related goals, is in the direct interests of customers and should not lead
6 to a cost disallowance in this case.

7
8 **Q. Do you have any other comment on the Division's recommendation to disallow a**
9 **portion of variable pay?**

10 A. Yes. Mr. Effron's testimony is that the attainment of financial goals is a benefit to
11 shareholders, but not to customers, and therefore, the variable pay associated with
12 achieving financial goals should not be recovered through rates. Although the
13 Commission has considered this issue in the past, the Company reiterates here that
14 customers do benefit from the Company's financial health for the following reasons:
15 (1) operating the distribution system requires a substantial amount of capital, and (2) the
16 cost of that capital is a direct function of the Company's financial health as compared to
17 other investment opportunities. Therefore, whether the Company uses equity or debt as a
18 vehicle for obtaining capital to fund operations in Rhode Island, the Company's financial
19 health is the *key determining factor* in the cost of equity and debt. Capital is lower cost
20 where the Company is viewed as being financially sound and capable of generating
21 strong performance over the long term. Since these outcomes are so critical to the
22 Company's business and customers, it is entirely appropriate that every employee's
23 annual pay be connected to some extent to the Company's financial goals.

1 **III. Union Labor Commitment**

2 **Q. Are you familiar with the Company's union contracts and the wage and benefit**
3 **costs arising therefrom?**

4 A. Yes.

5
6 **Q. The Division recommends that the Commission disallow \$1,363,000 in union**
7 **compensation costs that will be incurred by the Company under currently effective**
8 **union contracts because the Company has either added union positions without**
9 **work to perform or is planning to offset contractor work with union labor. Is the**
10 **Division correct?**

11 A. No. As addressed in the Rebuttal Testimony of Mr. Pettigrew, the increase in union labor
12 is needed to perform work on the Rhode Island distribution system that is incremental to
13 levels of work performed in the past. Mr. Effron only speculates that the increased cost
14 of union labor may be offset by a reduction in the use of outside contractors. However,
15 contractor usage is also driven by construction plans and workplan requirements, and the
16 Company's expectation is that it will need to use additional levels of both internal and
17 external labor resources to achieve its workplan goals. Moreover, I would note that
18 newly hired employees in the three covered union rosters require four to five years of
19 training and development to become qualified to perform their jobs. Therefore, except
20 for the rare exception of a new hire who is a fully qualified field worker, none of the new
21 union hires will be qualified to work independently at full rating for some time, which
22 obviates the Company's ability to supplant contractor resources with these new union
23 resources. The Division is not suggesting that the Company will avoid these costs or that
24 the costs are unreasonable. In fact, the Company is contractually committed to incur

1 these costs; the contractual commitment arises prior to the end of the Rate Year, and the
2 new workers will be put to work in furtherance of the Company's workplan without
3 causing an offsetting reduction to contract labor. Consequently, there is no basis for the
4 disallowance recommended by the Division.

5
6 **Q. Does this conclude your rebuttal testimony?**

7 **A. Yes.**

Rebuttal Testimony of
Robert L. O'Brien

REBUTTAL TESTIMONY
OF
ROBERT L. O'BRIEN

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1 **I. Introduction & Purpose of Rebuttal Testimony**

2 **Q. Please state your name and business address.**

3 A. My name is Robert O'Brien and my business address is 1753 Via Mazatlan, Rio Rico,
4 Arizona 85648.

6 **Q. Have you previously submitted testimony in this proceeding?**

7 A. Yes. I previously submitted direct testimony on behalf of the Company in its June 1,
8 2009 filing before the Rhode Island Public Utilities Commission ("Commission") in the
9 Docket. I also submitted Schedules NG-RLO-1 through NG-RLO-8 which accompanied
10 my testimony.

12 **Q. What is the purpose of your rebuttal testimony?**

13 A. My testimony is intended to illustrate the Company's rebuttal revenue requirement
14 position after corrections to the Company's originally filed position, adoption of certain
15 of the positions presented by the Division of Public Utilities and Carriers ("Division")
16 witnesses and updates in other positions based on more recent information. Section II of
17 my rebuttal testimony contains comparative schedules showing the Company's as filed
18 position compared to the Division's as filed position, Company updates and corrections
19 that have arisen since the original application was filed, and the Company's current
20 position based on its rebuttal presentation. In Section III, I address updates and
21 corrections to the Company's revenue requirement since its originally filed position.
22 Finally, in Section IV, I address certain adjustments proposed by the Division. I briefly
23 describe each item, cite the witness who raised the issue, discuss the issue and provide

1 additional information, if relevant, then summarize the topic and offer a recommendation.

2 I am responding to portions of the direct testimony of Division witnesses Effron and Gay
3 concerning adjustments to the Company's revenue requirement in the following areas:

4 A. Rate Case Expense and Amortization

5 B. Storm Fund Accrual

6 C. Storm Damage Expense

7 D. Injuries and Damages Expense

8 E. Outside Legal Expense

9 F. Uncollectible Accounts Expense

10 G. Merger Synergies and Costs to Achieve

11 H. Accumulated Depreciation

12 I. Cash Working Capital

13
14 **Q. Please identify the Rebuttal Schedules you are presenting.**

15 A. I am presenting the following Rebuttal Schedules:

- 16 • Schedule NG-RLO-R-1 Comparative and Updated Revenue Requirement
- 17 • Schedule NG-RLO-R-2 Uncollectible Expense Factor
- 18 • Schedule NG-RLO-R-3 Rate Year Plant in Service and Accumulated
- 19 Depreciation
- 20
- 21
- 22
- 23

24 **II. Comparative Position of Parties**

25 **Q. Please describe Schedule NG-RLO-R-1.**

26 A. Schedule NG-RLO-R-1 is a three page schedule that presents a comparison between the
27 as filed position of the Company and the Division together with the identification of

1 adjustments the Company is making to its as filed position and also the Company's
2 position on rebuttal. Page 1 shows the Company's as filed position in column (a), the
3 Division's adjustments in column (b) and the Division's as filed position in column (c),
4 by summary category with the proposed revenue deficiencies on line 27. Column (d)
5 contains a summary of the changes the Company is making to update and correct various
6 elements of its as filed presentation, which are shown on pages 2 and 3 of Schedule NG-
7 RLO-R-1 and which will be explained later in my testimony. Column (e) reflects the
8 Company's adoption or rejection of all or part of the Division's adjustments. Finally,
9 column (g) reflects the Company's rebuttal position, representing the sum of columns (c)
10 through (e).

11
12 Page 2, which contains the same columns as pages 1 and 3, provides the detail for the rate
13 base elements on lines 1 to 19 and the various components of the calculated return and
14 income taxes on lines 21 to 42, the summary of which are shown on page 1.

15
16 Finally, page 3 reflects the detail for the operating expenses in the same columns as pages
17 1 and 2, which are also summarized on page 1.

18
19 **Q. What is the Company's revenue deficiency, as a result of its rebuttal presentation?**

20 A. As shown on Schedule NG-RLO-R-1, page 1, line 27 in column (f), the Company's
21 rebuttal revenue deficiency is \$63,586,000.

1 **III. Company Updates and Corrections**

2 **Q. Is the Company proposing any changes to its originally filed revenue requirement**
3 **position?**

4 A. Yes, it is. The Company is proposing several changes which are also shown on Schedule
5 NG-RLO-R-1 in column (d).

6
7 **Q. Are other Company witnesses sponsoring rebuttal testimony in addition to your**
8 **testimony regarding other Division-proposed adjustments, the impacts of which are**
9 **also reflected on Schedule NG-RLO-R-1?**

10 A. Yes. Additional rebuttal testimony is being presented on other cost of service issues
11 contained in Schedule NG-RLO-R-1 by Company witnesses Messrs. Pettigrew, Dowd
12 and Mr. Wynter. In addition, there are several areas such as Customer Assistance
13 Advocacy and Economic Development program where there is no rebuttal testimony
14 because the Company believes the testimony presented in its direct filing on June 1, 2009
15 is sufficient.

16
17 **Q. What are the specific items that have been updated that are discussed in your**
18 **testimony?**

19 A. The Company has updated its Rate Year expenses originally included on Schedule NG-
20 RLO-2, as shown on Schedule NG-RLO-R-1 for:

21 A. Other Revenues – Page 3, Column (d), Line 2

22 B. Merger-Related Costs to Achieve – Page 3, Column (d), Line 23

23 C. Rent Expense Related to Capital Improvements – Page 3, Column (d), Line 24

1 D. Municipal Tax Expense – Page 3, Column (d), Line 34

2 E. Depreciation Expense – Page 3, Column (d), Line 31

3 F. Rate Base:

4 1. Plant in Service – Page 2, Column (d), Line 1

5 2. Accumulated Depreciation – Page 2, Column (d), Line 4

6 3. Accumulated Deferred Income Tax – Page 2, Column (d), Line 14

7
8 **A. Other Revenue**

9 **Q. Has the Company made any changes to the amount of Other Revenue reflected in**
10 **the Rate Year on Schedule NG-RLO-2, Page 1, line 4, column (e)?**

11 A. Yes. As indicated in the Company's response to Division Data Request 3-2, Rate Year
12 Other Revenues were overstated by approximately \$20,000. The correct amount of
13 Other Revenue is \$325,967 as opposed to \$346,207 as originally filed, resulting in a
14 reduction of \$20,240. This adjustment is reflected on Schedule NG-RLO-R-1, page 3,
15 line 2, column (d).
16

17 **B. Merger Related Costs to Achieve**

18 **Q. Please describe the change in the Merger-Related Costs to Achieve Synergy Savings.**

19 A. In providing the response to Division Data Request 3-4, the Company discovered that the
20 amount of non-recurring costs identified as costs to achieve merger synergies ("CTA")
21 that were removed from the cost of service was overstated. The specific elements in this
22 adjustment are described in detail in the Company's response to Division Data Request 3-
23 4. The net amount of the adjustment is \$399,245 which reduces the Known and

1 Measurable adjustment shown on Schedule NG-RLO-2, page 2, column (b), line 14 from
2 \$4,031,080 to \$3,631,835, as shown on Schedule NG-RLO-R-1, Page 3, line 23, column
3 (d).
4

5 **C. Rent Expense Related to Capital Improvements**

6 **Q. Please describe the adjustment made for the Rent Expense Related to Capital**
7 **Improvements at the Northborough, MA facility.**

8 A. In providing the response to Commission Data Request 2-41(d), the Company indicated
9 that the allocation percentage of the Northborough, MA facility to the Narragansett
10 Electric should have been 10.5 percent for, rather than the 12.24 percent used in the
11 Company's cost of service calculation. The Company updated its expense on Schedule
12 NG-RLO-2, page 14, line 5 based on the 10.5 percent allocation, reducing the original
13 Rate Year expense amount of \$323,494 by \$45,987 to \$277,507, as shown on Schedule
14 NG-RLO-R-1, Page 3, line 24, column (d).
15

16 **D. Municipal Tax Expense**

17 **Q. What is the adjustment the Company is making to the Municipal Tax Expense?**

18 A. As indicated in the Company's response to Division Data Request 1-25, the Company's
19 rate year municipal tax expense did not reflect the impact of the annual City of
20 Providence, Rhode Island tax credit associated with a municipal tax settlement agreement
21 reached on September 7, 2004 between the City and the Company. The correct amount
22 of rate year municipal tax expense on Schedule NG-RLO-2, page 26, line 15 is

1 \$19,201,998, reflecting a reduction of \$879,000, as shown on Schedule NG-RLO-R-1,
2 Page 3, line 33, column (d).
3

4 **E. Depreciation Expense**

5 **Q. What changes have been made to the Company's Rate Year Depreciation Expense?**

6 A. In its response to Division Data Request 11-27, the Company provided a revised
7 Schedule NG-JP-3 reflecting updated capital spending budget categories. While total
8 capital spending remained unchanged, the modification to the public requirements budget
9 category resulted in small adjustments to 2009 and 2010 distribution-related capital
10 additions, as well as associated removal and retirements costs. These changes resulted in
11 a reduction of \$9,150 in Rate Year depreciation expense on Schedule NG-RLO-2, Page
12 28, line 1 from \$41,465,676 to \$41,456,526, as shown on Schedule NG-RLO-R-1, Page
13 3, line 31. No changes have been made in the depreciation rates for either 2009 or 2010
14 or in the method or procedures in the depreciation expense calculation.
15

16 **F. Rate Base**

17 **Q. Has the Company made changes to Rate Base?**

18 A. Yes. As stated above, the Company provided updated capital spending by budget
19 category in its response to Division Data Request 11-27. The components of rate base
20 affected by the budget category modifications are Plant in Service, Accumulated
21 Depreciation and Accumulated Deferred Income Taxes.

1 **1. Plant in Service**

2 **Q. Please describe the changes to the Plant in Service for the Rate Year as shown on**
3 **Schedule NG-RLO-2, Page 34.**

4 A. The updated capital spending by budget category resulted in changes in plant additions
5 for 2009 and 2010, as shown on lines 3 and 24 of Schedule NG-RLO-2, Page 34, from
6 \$59,948,598 and \$75,931,916 to \$59,688,377 and \$75,831,027, respectively. These
7 changes resulted in a change in the plant retirements in each year since the plant
8 retirements are calculated using a 13.37 percent factor which has not changed since the
9 Company's initial filing. The combination of these changes reduced the Rate Year
10 Average Plant from \$1,232,746,925 as shown on line 22 of Schedule NG-RLO-2, Page
11 34 to \$1,232,477,804, as shown on Schedule NG-RLO-R-1, Page 2, line 1, column (f).

12
13 **2. Accumulated Depreciation**

14 **Q. What are the changes to the Rate Year accumulated depreciation amount reflected**
15 **on Schedule NG-RLO-2, Page 35?**

16 A. The change in the accumulated depreciation is the result of the changes in the plant in
17 service and depreciation expense discussed above. The net change in the accumulated
18 depreciation is an increase of \$65,940 which is the difference between the accumulated
19 depreciation on Schedule NG-RLO-2, Page 35, line 23 of \$516,525,305 and the revised
20 accumulated depreciation of \$516,591,245 on Schedule NG-RLO-R-1, Page 2, line 4,
21 column (f).

1 **3. Accumulated Deferred Income Taxes**

2 **Q. Please describe the changes to the Accumulated Deferred Income Taxes for the Rate**
3 **Year as shown on Schedule NG-RLO-2, Page 37.**

4 A. The accumulated deferred income taxes shown on Schedule NG-RLO-2, Page 37, line 20
5 changed from \$113,088,026 to \$113,066,754, for a reduction of \$21,272 due to the
6 change in book and tax depreciation resulting from the updated capital spending by
7 budget category in the Company's response to Division Data Request 11-27. This is
8 reflected on Schedule NG-RLO-R-1, Page 2, line 14.

9
10 **IV. Adjustments Proposed by Intervenor Witnesses**

11 **A. Rate Case Expense and Amortization**

12 **Q. Please identify the issue regarding rate case expense amortization.**

13 A. Mr. Effron, on page 9, lines 21 to 23 of his prefiled direct testimony, recommends a five-
14 year period for the amortization of the rate case expenses as opposed to the two-year
15 amortization period proposed by the Company.

16
17 **Q. What does Mr. Effron provide as support for his recommendation?**

18 A. Mr. Effron does not provide specific support for his use of a five-year period for the
19 amortization of rate case expenses. Rather, his recommendation is based on two
20 positions. First he states that, "...I do not believe that history should be entirely ignored."
21 and then, "[B]ased on the time interval between the Company's cases..."

1 **Q. Do either of these statements support the five-year period Mr. Effron uses for the**
2 **amortization of rate case expenses in this case?**

3 A. No, they do not. Both of those positions recommend using history as the basis for the
4 amortization period and do not recognize the current state of the economy or the facts
5 that exist for the Company or for most regulated companies today. Assuming a five-year
6 period between rate cases “Based on the time interval between the Company’s cases in
7 recent years” (Effron Testimony page 9, lines 21 to 22) is inappropriate. The Company is
8 currently operating under a long-term rate plan that became effective in May 2000 and is
9 scheduled to expire December 31, 2009. Under this plan, the ability to adjust rates and
10 the mechanisms for doing so were discreetly defined. Subsequent to the conclusion of
11 that rate plan, the Company expects that the dramatic increase in the need for
12 infrastructure replacement, as supported by Mr. Pettigrew, will dictate the need for more
13 frequent rate filings. Shorter periods between rate cases will be required to provide the
14 Company a reasonable opportunity to recover cost increases from inflation and also a
15 return on and of its investment required to serve customers. Shorter amortization periods
16 also result in smaller, more manageable rate increases for customers, as well as less
17 costly rate case processing since all parties have fewer years to review during the
18 preparation and processing of the future rate case.

19
20 **Q. Is there another reason to use the two-year amortization period?**

21 A. Yes. Since the Company expects the need to file more frequent cases, applying a five-
22 year amortization period for rate case cost recovery would compound the impact of this
23 cost recovery in future cases filed more frequently than five years apart.

1 **Q. How will this occur?**

2 A. If the Commission approves a five-year amortization of the \$1,730,000 in rate case
3 expense for this case as recommended by Mr. Effron, the Company would have an annual
4 amount of \$346,000 included in its rates. If, for example, the Company files its next rate
5 case in two years, this \$346,000 annual amortization would continue to be included in the
6 Company's cost of service, in addition to recovery of the costs of that future case. Rates
7 would therefore include recovery of costs for two rate cases.

8

9 **Q. What is the amortization period you recommend for this proceeding?**

10 A. I recommend the two-year amortization period which is supported by the Company's
11 current plans and provides the benefits discussed above to all parties.

12

13 **B. Storm Fund Accrual**

14 **Q. What is Mr. Effron's position regarding the annual funding of the Company's**
15 **Storm Fund?**

16 A. Mr. Effron recommends eliminating the annual collection and contribution to the
17 Company's Storm Fund which is intended to insulate customers from rate shock
18 associated with major storm events. His position, on page 16, lines 17 to 19 of his
19 testimony, is based on his belief that, "...the present credit balance, along with the
20 continuing credits for interest and attachment fee revenue, is more than adequate to
21 provide for all but the most catastrophic of storms."

1 **Q. Do you agree with Mr. Effron's elimination of the \$1,041,000 from the test year**
2 **expenses in this proceeding?**

3 A. No, I do not. The purpose of the Storm Fund is to provide funds immediately available to
4 the Company to support recovery from damage caused by major and catastrophic storm
5 events. As such, making a decision based on an assumption that the fund balance "...is
6 more than adequate to provide for all but the most catastrophic of storms" is not prudent
7 and should be rejected.

8
9 **Q. Does the Storm Fund provide benefits to the customers?**

10 A. Yes, it does. The Storm Fund, which can be used for storms where the Company incurs
11 more than \$728,000 in storm recovery expenditures for a single storm, provides a
12 protection for the Company's customers because they are less likely to be facing a
13 significant rate increase to pay for the recovery of costs for a catastrophic storm. In
14 addition, as the Division points out, storm fund reserves accrue interest for the benefit of
15 customers. The opposite, however, is also true with storm fund deficits accruing interest
16 on behalf of the Company. While the Company has not incurred a catastrophic storm
17 event in a number of years one need only look at the damage sustained by the Company's
18 affiliate, Massachusetts Electric Company, from the devastating ice storm that struck its
19 service territory in December 2008. Massachusetts Electric also had a significant Storm
20 Fund reserve of approximately \$28 million at the time of the ice storm but incurred more
21 than \$62 million of storm recovery and restoration costs as a result of that storm event.
22 The customers of Massachusetts Electric are now facing the need to replenish a fund
23 deficiency in excess of \$30 million and are being charged interest on the deficit balance

1 in the interim. While storms of this magnitude cannot be predicted, periodic storms of a
2 significant nature are inevitable. Of particular concern to the Company's service territory
3 is the potential for catastrophic damage resulting from hurricanes. While the Storm Fund
4 has operated as intended throughout the period of its existence, the potential for
5 catastrophic damage caused by major storms or a major hurricane should not be
6 overlooked. Accordingly, the fund is operating in a fashion that has provided great
7 benefit to customers and the Company alike by having funds available to fund its
8 immediate response to storm events.

9
10 **Q. Did Mr. Effron provide any data as to the costs related to the recovery from large,**
11 **catastrophic and the most catastrophic storms?**

12 A. No, Mr. Effron simply presented his opinion that the existing balance in the Storm Fund
13 and related continuing credits is, "...more than adequate to provide for all but the most
14 catastrophic storms."

15
16 **Q. Should the suspension of annual Storm Fund collections be removed from the Rate**
17 **Year expense as recommended by the Division?**

18 A. No, it should not. The Storm Fund has been established to provide for the restoration and
19 recovery of service for customer from damage caused by large and catastrophic storms.
20 To stop this accrual based purely on the Division's opinion that the Storm Fund reserve is
21 adequate is not appropriate and would serve to defeat the purpose of establishing and
22 maintaining the Storm Fund.

1 **C. Storm Damage Expense**

2 **Q. What is Mr. Effron's recommendation for a Test Year amount for storm damage**
3 **expense, which covers the repair and restoration costs for storm recovery**
4 **expenditures of less than \$728,000 for a single storm?**

5 A. Mr. Effron recommends not using the actual storm recovery and restoration costs
6 incurred by the Company in the Test Year 2008, but to instead use a five-year average for
7 the years 2004 to 2008 of \$3,164,000.

8
9 **Q. Do you think use of a five-year average is a reasonable approach to determine the**
10 **Rate Year level for expenses to repair and restore services from storm damage in**
11 **the Rate Year?**

12 A. No, I do not. I think use of a five-year average relies too heavily on historic years and
13 distorts the current activity.

14
15 **Q. Did the Company determine that there needed to be an adjustment to the recorded**
16 **2008 storm damage expense used in Mr. Effron's calculation?**

17 A. Yes. In developing his average calculation, Mr. Effron relied on the storm damage
18 expense amounts provided by the Company in its response to Division 23-1(b). In
19 reviewing its response, the Company determined that the amount reflected in the 2008
20 Test Year cost of service of \$5,168,131 in that response should have been \$4,932,963.
21 The reduction of \$235,168 reflects the sum of Known and Measurable Adjustments
22 which were made to the Company's cost of service in this proceeding reflected on NG-
23 RLO-2, Page 2, line 22, column (b) and NG-RLO-2, Page 3, line 13, column (b) related

1 to the December 2008 ice storm costs charged to the Company that were subsequently
2 reversed in January 2009.

3
4 **Q. Are there any other adjustments that should be reflected to the 2008 storm damage**
5 **expense?**

6 A. Yes. Upon reviewing the 2008 storm expense data, the Company discovered costs
7 associated with a July 2008 storm which exceeded the \$728,000 threshold for Storm
8 Fund recovery. Costs associated with this storm amounted to \$897,562, of which
9 \$522,562 (after applying the Company's \$375,000 deductible) should have been deferred
10 against the Storm Fund and not included in the cost of service presentation.

11
12 **Q. What is the result of removing these two items from the \$5,168,131 in storm damage**
13 **expense reflected in Mr. Effron's calculation?**

14 A. As stated above, the adjusted Test Year amount included in the cost of service was
15 \$4,932,963, or the \$5,168,131 incorrectly included with the response to Division 23-1(b)
16 less the Known and Measurable Adjustments of \$235,168 related to the December 2008
17 ice storm, which have already been deducted from the cost of service as filed. This
18 amount should then be adjusted downward by \$522,562 associated with the July 2008
19 storm that should have been deferred, resulting in a normalized Test Year amount of
20 \$4,410,401. Schedule NG-RLO-R-1, page 3, line 17, column (d) reflects the latter
21 adjustment to the Company's revenue requirement position.

1 **Q. How does the normalized Test Year Amount of \$4,410,401 compare to other**
2 **historical years of storm damage expense used in Mr. Effron's calculation?**

3 A. Once normalized for the July 2008 storm that should have been deferred, the Test Year
4 amount of \$4,410,401 is representative of storm damage expense incurred by the
5 Company during the three year period of 2005 through 2007, in which costs ranged from
6 \$2.9 million to \$4.1 million.
7

8 **Q. What is your recommendation for the Rate Year level of storm damage expense?**

9 A. I recommend use of the actual expenses in the Test Year as adjusted, \$4,410,401, because
10 it represents the most recent activity for storm related expenditures incurred in the Test
11 Year period, upon which rates are intended to be set. This results in an adjustment of
12 (\$522,562) from the Company's cost of service to reflect Test Year recorded storm
13 expenses that should have been deferred as a qualifying storm to the storm fund.
14

15 **D. Injuries and Damages Expense**

16 **Q. What is the recommendation of Mr. Effron with regard to the Injuries and Damage**
17 **("I&D") expense for the Test Year?**

18 A. Mr. Effron, after comparing the Test Year recorded amount to a three-year average of the
19 I&D expense using the years 2005 to 2007, without an adjustment for inflation in that
20 three-year period, recommends removing an accrual for I&D of \$2.5 million and using
21 the remaining balance for 2008 of \$4,555,000 (\$7,055,000 less \$2,500,000) as the Rate
22 Year level.

1 **Q. Does Mr. Effron provide rationale for the use of a three-year average in his**
2 **calculations for the I&D Test Year level of expense?**

3 A. No, he does not.
4

5 **Q. Does he provide any support for not using the \$2.5 million which is related to**
6 **financial terms associated with the potential settlement of litigation?**

7 A. Mr. Effron cites the Company's responses to Division Data Requests 1-29 and 23-3 in
8 which the Company indicates that the increase in Test Year I&D expense is related to
9 increased claims reserves, principally associated with a potential settlement of litigation
10 of a case from 2004. He then goes on to label the \$2.5 million as a "non-recurring" and
11 simply removes it from consideration either in the Test Year or as part of his proposed
12 historic average for this expense.
13

14 **Q. Should this \$2.5 million be removed from the establishment of Test Year or Rate**
15 **Year expenses in this proceeding?**

16 A. No, it should not. This is an actual expense that the Company will likely incur again and,
17 while it may be greater than similar expenses in the prior year, it is not out of line with
18 2006 expense levels. As such, the level of expense in the test year is not a "non-
19 recurring" event. Furthermore, the I&D expense in every year contains claims reserves
20 which are based on the best available information from legal, insurance, and accounting
21 personnel. If one of these actions can be summarily removed because someone labels it
22 as "non-recurring", then any or all of the separate claims adjustments, either positive or
23 negative, could be labeled as non-recurring. The fact is that the activity causing this

1 specific reserve requirement is the same as many other activities where the Company
2 must respond to claims made by other parties and must reflect a reasonable amount for
3 the final expenses, whether through litigation or settlement, on its accounting records.
4 The accrual for the \$2.5 million results from the same and normal activities encountered
5 by the Company many times during a year, only the amount is the different.
6

7 **Q. What is your recommendation for the amount of I&D that should be reflected in the**
8 **Test Year?**

9 A. Consistent with storm damage expense, I believe that the Test Year amounts are the best
10 reflection of the costs the Company will be incurring in the future, adjusted for inflation,
11 and should be used to establish the base Test Year amount.
12

13 **E. Outside Legal Expense**

14 **Q. What is Mr. Effron's position with regard to Test Year Outside Legal expense?**

15 A. Mr. Effron recommends removing legal expenses of \$419,000 incurred by the Company
16 in 2008 because the specific case that caused the Company to incur those expenses has
17 been closed. He therefore makes the assertion that these costs will not recur in the future
18 and therefore should be removed from the Test Year expenses.
19

20 **Q. Do you agree with Mr. Effron's position regarding the removal of those expenses**
21 **from the Test Year expenses?**

22 A. No, I do not. Again, Mr. Effron seeks to remove expenses simply by labeling them as
23 "non-recurring". The fact in this expense category, as it was with Injuries and Damages,

1 is that while the legal expenses related to the specific case referenced by Mr. Effron, the
2 Constellation Energy FCM Dispute Matter, will not likely recur, there have been and will
3 continue to be many instances where the Company will need to employ outside legal
4 assistance to defend the interests of the Company and its customers. This item is, in my
5 opinion, a recurring event because the Company will always have separate litigation
6 where outside legal assistance will be required, whether for cases related to the same or
7 different issues than those that were litigated in the past. Adopting the Division's
8 recommendation to disallow legal expense related to this particular matter on the basis
9 that, "... this matter has been resolved. Therefore, this expense will not be incurred
10 prospectively and should be removed from the Company's revenue requirement." would
11 suggest that the Company should not be allowed to recover costs for any matters that
12 would conclude prior to the Rate Year.

13
14 **Q. Do you feel that Mr. Effron's position of excluding the Test Year expenses is in**
15 **accordance with sound rate-making principles?**

16 A. No, I do not. Such a position is contrary to the underlying principal for using a "test
17 year" to establish the Company's cost of service. The test year should include a level of
18 expense for normally recurring activities such as the use of outside legal support. The
19 fact is that expenses for outside legal assistance are recurring and the removal of the
20 expense for a specific case should not be made simply because that case is completed. It
21 is undisputed that most, if not all legal cases will conclude at some point in time, but
22 those cases are replaced by subsequent cases which will likely deal with different issues
23 than the prior cases.

1 **F. Uncollectible Accounts Expense**

2 **Q. On what portions of the Division's presentations regarding uncollectible accounts**
3 **will you be presenting rebuttal testimony?**

4 A. I will be providing rebuttal testimony to the presentation of Mr. Effron regarding the
5 inclusion of uncollectible expense related to the Company's accounts receivable
6 associated with what it bills its customers for transmission service and to the presentation
7 of the testimony of Mr. Gay regarding his calculation of the uncollectible rate of 0.71
8 percent on page 25 of his testimony.

9
10 **Q. Please describe Mr. Effron's recommendation regarding the inclusion of**
11 **uncollectibles related to transmission service.**

12 A. Most importantly, Mr. Effron disputes neither the prudence nor the recoverability of
13 uncollectible expense related to billings for recovery of transmission service expenses.
14 Mr. Effron's recommendation is only that the uncollectibles related to transmission
15 service be excluded from the determination of distribution rates. His position is that
16 since these uncollectibles are related to transmission service, "uncollectible accounts
17 expense related to transmission service should be assigned to the transmission cost of
18 service" and presumably recovered through the transmission service rates billed by the
19 Company to its distribution customers, and not from distribution service rates.

20
21 **Q. Do you agree with Mr. Effron?**

22 A. Yes, in principal I do. The Company does not provide transmission services for its
23 distribution customers, but rather is billed for transmission services by the ultimate

1 transmission service providers and, in turn, bills its distribution customers for those
2 incurred expenses on a dollar for dollar basis through the transmission charge. As such,
3 the Company's current "transmission cost of service" includes only expenses it incurs for
4 transmission services provided by the ultimate transmission service providers. I concur
5 with Mr. Effron that the Company's transmission cost of service should include
6 uncollectible accounts expense related to its transmission charge revenues and that they
7 should be recovered as a component of the transmission charge rather than the current
8 practice of including recovery of such costs in the Company's distribution rates. If the
9 Commission concurs with this treatment, the Company proposes to mirror its proposed
10 mechanism for recovery of commodity-related uncollectible accounts as a component of
11 commodity rates expense for recovery of transmission charge-related uncollectible
12 expense in its transmission charge rates.

13
14 **Q. What is the impact on the Company's cost of service of shifting the recovery of**
15 **transmission-related uncollectible accounts expense from distribution rates to the**
16 **transmission charge?**

17 A. Of the total uncollectible expense of \$5.020 million as shown on Schedule RLO-2, Page
18 1, Line 16, column (h) \$1.361 million relates to transmission charge revenue using the
19 Company's proposed uncollectible percentage of 1.0975%. Consequently, if the
20 Commission agrees that the uncollectible accounts expense related to its transmission
21 charge revenues should be recovered through the Company's transmission charge
22 revenues, this amount should be removed from the distribution revenue requirement in
23 this proceeding. In doing so, commencing March 1, 2010, with a lost revenue provision

1 retroactive to January 1, 2010, the Company should include in its transmission cost of
2 service for recovery from its transmission charge an allowance for uncollectible accounts
3 expense equal to 1.0975%. This amount should be reconciled to actual transmission
4 charge-related uncollectible accounts expenses annually.

5
6 **Q. Have you made an adjustment to Schedule NG-RLO-R-1 to reflect the reduction in**
7 **uncollectible expense for the \$1,361,000 of uncollectible expense related to the**
8 **transmission revenue?**

9 A. No, I have not. The adjustment should be made upon agreement by the Commission that
10 these amounts should be collected in the transmission charge.

11
12 **Q. Referring to the testimony presented by Mr. Gay, what areas of his calculation on**
13 **page 25 of his prefiled testimony will you address?**

14 A. I will present two adjustments to Mr. Gay's calculation that resulted in his proposed
15 uncollectible rate for the Test Year of 0.71 percent. I will also present two adjustments,
16 one to revenue and one to operating expenses that I believe need to be made to the
17 Company's pro forma Test Year revenue and expenses if his concepts are adopted by the
18 Commission, which they should not.

19
20 **Q. Should his hypothetical theory and concepts be adopted in place of the data**
21 **presented by Mr. Wynter from the actual records of the Company?**

22 A. No, they should not. Mr. Gay presents pages of theoretical calculations and suppositions
23 that he uses to tell the Company what the Company should have done over the last

1 several years, including the Test Year. At best, if the Commission believes that the
2 proposals made by Mr. Gay, including earlier disconnection of customers, should be
3 adopted by the Company, the Commission should advise the Company in this case and
4 take action to reflect the results of those actions in the next case filed by the Company.
5 The Company should not have the substantial penalty imposed on it without having an
6 opportunity to implement these procedures, incur whatever additional costs are associated
7 with the additional activities included in Mr. Gay's proposal and present the results in the
8 next rate case filed by the Company.

9
10 **Q. Assuming, for the purpose of rebuttal, that the Commission would consider**
11 **adopting Mr. Gay's proposals, are there any adjustments that are required to his**
12 **calculations on page 25 of his prefiled direct testimony?**

13 A. Yes, there are. First, assuming Mr. Gay's theories work, it is very likely that the amount
14 of 2008 charge-off recoveries ("CO Recoveries") of \$463,961 shown on page 25 of Mr.
15 Gay's testimony from the Company's actual results would be less since the amounts of
16 uncollected accounts receivable turned over for collection would be less under Mr. Gay's
17 procedures. Assuming the ratio of total charge-offs between Mr. Gay's calculations,
18 \$8,012,536 (\$12,876,812 less \$4,864,276), and the Company's actual results,
19 \$12,876,812, which is a ratio of 62.225 percent (\$8,012,536 divided by \$12,876,812) the
20 Company's actual amount of recoveries of \$463,961 would be reduced to \$288,700 as
21 shown on Schedule NG-RLO-R-2 on line 13. This would increase Mr. Gay's calculated
22 amount by another 0.01 percent to a revised amount of 0.72 percent. Second, if the 5,449
23 residential accounts were written off during 2008, there would be fewer customers

1 providing revenue to the Company during the Test Year and for each year into the future.
2 This requires a reduction in revenue both for use in Mr. Gay's calculation and also for the
3 Test Year revenue. Using Mr. Gay's customer and revenue estimates, there would be a
4 reduction in annual revenue of \$5,427,204 as shown on Schedule NG-RLO-R-2, line 15
5 in column (c), as calculated in note [b] at the bottom of the page. This results in an
6 additional increase in Mr. Gay's rate to 0.73 percent, as shown on line 16 of column (d).
7

8 **Q. Does this adjustment for the revenue lost when the customers are disconnected**
9 **earlier than under the Company's existing procedures have other implications?**

10 A. Yes, it does. If the procedures recommended by Mr. Gay were in effect for the Test Year
11 2008, it must be assumed that they were in effect in 2007 also. As such, the 5,449
12 decrease in the number of accounts used by Mr. Gay for his reduction in uncollectibles
13 must be assumed to be off the Company's customer list and therefore not billed for the
14 entire Test Year. In any event, they would not be customers during the Rate Year,
15 meaning the Company would not have had revenue from billings to these customers.
16 This results in a reduction of revenue at present rates of \$5,427,204 as shown on
17 Schedule NG-RLO-R-2, line 15, column (c).
18

19 **Q. Could this adjustment to revenue be greater for future years as the number of**
20 **disconnected customers continues to increase?**

21 A. Yes it could. Even if we make the assumption that some of the dwellings that were
22 disconnected reconnect with new owners, the additional disconnections could likely
23 exceed those possible reconnections. In any event, the annualized number of 5,449

1 presented by Mr. Gay is likely to be a permanent reduction in the Company's customer
2 base.

3
4 **Q. What does this mean with regard to the Company's revenue requirement?**

5 A. The Company's revenue at present rates would decrease by \$5,427,204 as a direct result
6 of the early disconnection of customers based on Mr. Gay's recommended procedures.

7
8 **Q. Please describe the final adjustment required if Mr. Gay's recommendation is**
9 **adopted?**

10 A. If the Commission adopts Mr. Gay's recommended procedures, which it should not as I
11 have previously stated, the Company would have to recover the additional costs
12 associated with the early disconnection of customers resulting from Mr. Gay's
13 recommendation procedures.

14
15 **Q. What are the additional costs associated with the implementation of Mr. Gay's**
16 **recommendation?**

17 A. These additional costs, estimated to be approximately \$33,000 per year, would be
18 necessary to handle the additional work to implement the additional disconnections on a
19 regular basis in the future.

1 **Q. Please summarize your rebuttal testimony to Mr. Gay's proposals.**

2 A. I believe that Mr. Gay's recommended proposals should not be used to establish revenue
3 requirements in this proceeding and the two-year average of 1.0975 percent calculated on
4 Schedule NG-RLO-2, page 25, line 5, column (d) should be used.

5
6 **G. Merger Synergies and Costs to Achieve**

7 **Q. Has Mr. Effron proposed an adjustment to the Company's proposed sharing of net**
8 **Merger Synergies?**

9 A. Yes, he has.
10

11 **Q. Would you please describe Mr. Effron's recommendation?**

12 A Mr. Effron is proposing to treat CTA for years 1 and 2 of the ten-year synergy savings
13 analysis period differently than CTA expected in years 3 through 10. The Division
14 proposal assumes that the Company's ten-year synergy savings analysis period
15 commences with calendar year 2008, or the year immediately follow the merger of
16 National Grid and KeySpan. For years 1 and 2, or calendar years 2008 and 2009, the
17 Division is proposing a year-on-year match of CTA with the annual synergies presumed
18 for those years only. For the years 3, or calendar year 2010, through year 10, the
19 Division is proposing an amortization of CTA, presumably to match the CTA with the
20 resulting annual synergy savings produced over the entire remaining eight years of the
21 ten-year synergy savings analysis period. However, the proposal abandons the
22 CTA/synergy matching principal for the first two years and reverts to such a matching
23 principal in the 2010 rate year of this proceeding, or year 3 of ten-year synergy savings

1 analysis period. The Division proposes a straight line amortization of total CTA expected
2 for years 3 through 10 over the remaining eight years of the analysis period. The CTA
3 assumed for year 1 and 2 amounts to approximately \$8,610,000, or roughly 54% of the
4 total CTA included in the synergy savings analysis. The Division proposes to match, or
5 amortize, the remaining 46% of total CTA expected to be incurred in years 3 through 10,
6 or approximately \$7,395,000 over an eight- year period commencing in the Rate Year of
7 this proceeding. The Division's proposed annual amortization is \$924,000 (\$7,395,000
8 divided by 8), or \$1,176,000 less than the Company's proposed annual amortization of
9 \$2,100,000.

10
11 **Q. Do you agree with this \$1,176,000 adjustment to the Company's cost of service?**

12 A. No, I do not

13
14 **Q. Please elaborate.**

15 A. In theory, each dollar of CTA, regardless of when it is incurred, results in some enduring
16 merger synergy savings. It is inappropriate to match one-time CTA with the resulting
17 annual, and continuing, synergy savings produced in only a given year and assume that
18 future synergy savings have no correlation to CTA that were incurred in a previous year.
19 However, the Division's proposal appears to do just that in years 1 and 2 of the ten-year
20 analysis period. The underlying basis of the Division's adjustment is that based on the
21 estimates of one-time costs to achieve and the resulting annual and enduring merger
22 synergy savings. Mr Effron, at page 23, lines 11 – 15 of his testimony states, "...the
23 CTA incurred in Year 1 and Year 2 have more than paid for themselves by expense

1 reductions retained by shareholders. Consequently, the Year 1 and Year 2 CTA should
2 not also be recovered from ratepayers prospectively as this would result in a double
3 recovery.”
4

5 **Q. Do you disagree with this position?**

6 A. For the most part, yes I do disagree. The Company strongly disagrees that the enabling
7 CTA assumed in years 1 and 2 should not be reflected any differently in the analysis than
8 CTA assumed in any other year. The Company’s proposal appropriately matches costs
9 and benefits over a ten-year analysis period in order to properly match 100% of expected
10 synergies with 100% of expected CTA over the full analysis period. Indeed, the
11 Division’s proposal adopts this matching principal for CTA expected in years 3 through
12 10, as Mr. Effron States on page 23, Lines 17 – 19 of his testimony, “I recommend that
13 this amount be amortized over eight years, the remainder of the ten year time frame
14 considered in the Company’s synergy savings analysis.” This appears to be in direct
15 contradiction to year-on-year matching that the Division suggests is appropriate for years
16 1 and 2. As indicated earlier, 54% of the roughly \$16,005,000 of total expected CTA are
17 reflected in years 1 and 2 in the synergy savings analysis and 46% are reflected in years 3
18 through 10. Conversely, of the total \$81,527,000 of expected synergy savings included
19 in the synergy savings analysis, roughly \$9,471,000, or only 12%, is reflected in years 1
20 and 2 and the remaining 88% is reflected in years 3 through 10. Matching 54% of total
21 CTA with 12% of total expected synergy savings hardly seems like a balanced proposal.

1 **Q. You indicated that you disagreed “for the most part” with the Division’s position**
2 **concerning this issue. What did you mean by that?**

3 A. While the Company strongly disagrees with the proposed Division adjustment to CTA
4 amortization expense of \$1,176,000, it does agree that the Company proposal would
5 result in an element of double recovery of CTA as suggested by the Division. The
6 Company agrees that the amortization period for the CTA should commence as of
7 calendar year 2008, the first year in which the Company began incurring CTA and began
8 generating the resulting synergy savings. This would ensure a proper matching of 100%
9 of the expected CTA and 100% of the expected resulting synergy savings over the ten-
10 year analysis period. However, the proper remedy, consistent with appropriately
11 matching the CTA with the resulting synergies over the full ten-year period, is to
12 commence the amortization of CTA as of calendar year 2008, the beginning of the ten-
13 year synergy savings analysis period. While no adjustment is required to the Company’s
14 proposed cost of service in this proceeding, the Company’s proposal must be modified to
15 limit the inclusion of CTA amortization and its 50% share of net synergy savings in its
16 future costs of service to eight years commencing with the 2010 Rate Year in this
17 proceeding, rather than the ten years originally proposed by the Company. This will
18 properly eliminate the double recovery of CTA amortization in years 1 and 2 (2008 and
19 2009). This will also be consistent with the Division’s proposed eight-year amortization
20 period commencing with the 2010 Rate Year in this proceeding. Finally, this approach is
21 balanced and would avoid the lopsided matching of 54% of CTA with 12% of synergy
22 savings in years 1 and 2 and matching 46% of CTA with 88% of synergy savings for the
23 remaining eight-year period as suggested by the Division.

1 **Q. Is the Division proposing any other limitations on the sharing of net synergy**
2 **savings?**

3 A. Yes, it is. The Division proposes to subject the Company to a synergy savings proof
4 before allowing the inclusion of CTA amortization or the Company's share of net
5 synergy savings in its cost of service in future cases during the eight-year period
6 commencing with 2010.

7
8 **Q. Do you agree with this recommendation?**

9 A. No, I do not. The Company's proposal in this case advances an amount of steady state
10 synergy savings to customers ahead of the expected achievement of those savings.
11 Steady state synergy savings are not expected to be fully realized until year four of the
12 ten-year synergy savings analysis period, or calendar year 2011. The Company's
13 proposal advances the incremental customer share of steady state savings expected in
14 2011 versus 2010 by crediting the cost of service in this proceeding by the customer
15 share of steady state synergy savings not expected until 2011. The total incremental
16 amount of expected savings from 2010 to 2011 is approximately \$1,612,000, the
17 customer 50% share of which amounts to \$806,000. (See NG-RLO-3, page 5, line 16,
18 columns (c) and (d)). This incremental 50% customer share of net synergy savings is
19 included in the Company's Rate Year cost of service, or 2010, in this proceeding. The
20 Company believes that this synergy savings advance provides real value to customers by
21 avoiding the need for customers to wait until a future rate case to enjoy the benefits of
22 post-Rate Year synergy savings. This advanced customer benefit, along with the right to
23 include CTA amortization and the Company's 50% share of net synergy savings in its

1 cost of service in future rate cases without the need for a proof of savings, were key
2 components of the Company's proposal with respect to merger synergy savings in this
3 proceeding.
4

5 **Q. Has the Commission considered similar treatment in previous cases?**

6 A. Yes, it has. In the recently decided rate case for the Company's gas operations in Rhode
7 Island in Docket No. 3943, the Commission approved an identical synergy savings
8 proposal. In that case, the Company and the Division agreed to a stipulation which
9 imposed no proof of savings requirement for inclusion of CTA amortization and
10 Company share of net synergies in costs of service in future rate cases filed up to five
11 years from the Commission's order in that case. For the next five years following the
12 initial five years, the Company's right to include CTA amortization and Company share
13 of net synergies in costs of service was subject to a stipulated proof of savings formula.
14

15 **Q. Did the Commission approve the stipulation in that case?**

16 A. Yes, it did.
17

18 **Q. What is your recommendation with respect to the Division's proposed adjustment to**
19 **CTA amortization in this proceeding?**

20 A. I recommend that the Commission reject the Division's proposed adjustment to CTA
21 amortization expense of \$1,176,000. In addition, the Company's inclusion of CTA
22 amortization and Company share of net synergy savings in costs of service in future rate
23 case should be limited to an eight-year period commencing with the Rate Year in this

1 proceeding, or calendar year 2010, rather than the ten-year period originally proposed by
2 the Company.

3
4 **H. Accumulated Depreciation**

5 **Q. It appears that Mr. Effron is recommending a decrease in the Company's proposed**
6 **net plant in service for the Rate Year, but is also recommending an increase in the**
7 **accumulated depreciation for the Rate Year, is that correct?**

8 A. Yes, it is. Mr. Effron recommends a total reduction in the Company's proposed Rate
9 Year net plant in service of \$32 million dollars, with an average Rate Year reduction of
10 \$20 million. Normally a reduction of this magnitude would also result in a decrease in
11 the depreciation expense and the related accumulated depreciation. However, because
12 the plant retirements and cost of removal elements are based on prior percentage
13 relationships to plant-in-service, there is a decrease in those amounts in the determination
14 of the accumulated depreciation which actually results in increasing accumulated
15 depreciation.

16
17 **Q. Have you prepared a schedule reflecting these changes and calculations?**

18 A. Yes, I have. Schedule NG-RLO-R-3 contains all of the data related to the determination
19 of average Rate Year plant and accumulated depreciation as presented by the Company,
20 proposed by Mr. Effron and the Company's revised Rate Year amounts for each
21 component.

1 **Q. Please describe Schedule NG-RLO-R-3.**

2 A. Schedule NG-RLO-R-3 is a one page document which shows the calculations of utility
3 plant and accumulated depreciation at December 31, 2009 and 2010 for the Company as
4 filed, the Division as filed and the Company as updated in rebuttal. The utility plant
5 shows the plant additions and retirements for each year while the accumulated
6 depreciation shows the addition of depreciation expense and the reduction for plant
7 retirements and the cost of removal. The format of the presentation shows each of the
8 components for each period.

9

10 **Q. Please describe the amounts reflected on NG-RLO-R-3 in column (b).**

11 A. The amounts shown in column (b) represent the Company's net plant in service and
12 accumulated depreciation calculations as originally filed on Schedule NG-RLO-2, Pages
13 34 and 35, respectively.

14

15 **Q. Please describe how you determined the Division As Filed and the Division**
16 **Adjustments shown in columns (d) and (c), respectively.**

17 A. The amounts shown in column (d) were taken from Mr. Effron's Schedule DJE-8.1 and
18 Schedule DJE-5 or were calculated using the totals on DJE-8.1 and the percentages
19 referenced in the footnotes which were derived from Company schedules as noted by Mr.
20 Effron. For example, the net plant additions in column (d) on line 4 of \$43,678,000
21 reflects the doubling of Mr. Effron's January through June 2009 plant in service increase
22 of \$21,839,000, as shown the third line of Schedule DJE-8.1 . This number was grossed
23 up to provide for the plant retirements using the 13.372 percent of plant as reflected in

1 Mr. Effron's footnote D. The average Rate Year plant balance shown by Mr. Effron of
2 \$1,212,525,000 is shown on Schedule NG-RLO-R-3, line 10, column (d). Mr. Effron's
3 net reduction in Rate Year plant in service of \$20,223,000 is shown on Schedule DJE-5
4 and also on line 10, column (c) of Schedule NG-RLO-R-3.

5
6 **Q. Please describe the Company Update in column (e).**

7 A. Column (e) reflects the adjustments in each of the categories required to reach the revised
8 plant additions for 2009 and the Rate Year as a result of updated capital spending by
9 budget category, discussed earlier in my testimony and in the Company's response to
10 Division Data Request 11-27. The revised plant additions of \$59,688,000 on line 2 in
11 column 6 and the \$75,831,000 on line 6 in column (b) are supported by Mr. Pettigrew
12 and are the basis for the remaining calculations.

13
14 **Q. What is the significance of your presentation on Schedule NG-RLO-R-3?**

15 A. This schedule shows all of the components affected when plant additions are changed. It
16 is important to understand the relationship of the plant retirements and cost of removal
17 elements when making this change because it shows that an artificial reduction in plant
18 additions, as proposed by Mr. Effron, will have impacts on other rate base components
19 unless each component is reviewed, which Mr. Effron did not do in making his reduction
20 to plant additions.

1 **I. Cash Working Capital**

2 **Q. Do you agree with Mr. Effron's removal of the Contract Termination Charges**
3 **("CTC") from the calculation of the Cash Working Capital ("CWC")?**

4 A. No, I do not. Mr. Effron notes, on page 32, lines 6 to 9, "All CTC costs eligible for
5 recovery are addressed in those settlements. To the extent that the CTC are under or
6 over-recovered in any given year, a return is calculated on such under or over-recovery
7 and included in the reconciliation." However, the return on under or over-recovery to
8 which Mr. Effron refers does not address the lag between inclusion in the revenue
9 requirement and collection from customers. In addition, the CWC effect is related to the
10 utility's role of collecting the CTC costs and not to the cost themselves. As Mr. Effron
11 acknowledges, on page 32, lines 9 and 10, "To my knowledge, there is no provision for a
12 separate return on any cash working capital effect of the CTC expenses." It appears that
13 Mr. Effron is discussing the wholesale CTC mechanism as approved by the Federal
14 Energy Regulatory Commission. However, Mr. Effron does not address the transaction
15 between the Company and its customers and the payment lag associated with that
16 transaction, and it would be inappropriate not to recognize this cost to the Company.

17
18 **Q. Do you agree with Mr. Effron that the CWC percent used in Docket No. 3943**
19 **should be used in this proceeding for the municipal tax CWC percent in this**
20 **proceeding?**

21 A. No, I do not. I did not participate in that case and do not know how that data was
22 developed. Mr. Effron does not present any support for the use of the data from that case,

1 he only states that, in his opinion, my testimony, "...is not an adequate explanation of the
2 discrepancy."

3
4 **Q. Does Mr. Effron present any support for the data presented in Docket No. 3943?**

5 A. No, he does not. Mr. Effron only presents the result that was used in that proceeding.
6

7 **Q. Should Mr. Effron's proposed use of data from Docket No. 3943 be used in place of
8 the Company's presentation in this proceeding?**

9 A. No, it should not. I have reviewed a selection of the municipal tax bills and believe that
10 those periods, which are mostly a tax year of July to June are appropriate for use in the
11 CWC calculation and that the resulting 33.77 percent should be used in the calculation of
12 CWC in this proceeding.
13

14 **V. Conclusion**

15 **Q. Does this conclude your direct testimony?**

16 A. Yes it does.

Schedule NG-RLO-R-1

Comparative and Updated Revenue Requirements

The Narragansett Electric Company d/b/a National Grid
Comparative And Updated Revenue Requirement
For the Twelve Months Ended December 31, 2010

Line #	Description	Reference Or Factor	Cost of Service (\$ in Thousands)					Revised Company Position
			Company As Filed (a)	Division Adjustments (b)	Division As Filed (c)	Updates & Corrections (d)	Company Adjustments Rebuttal (e)	
					(a) + (b)			Sum (e) to (e)
1	Rate Base	Pg 2, L 19	\$ 623,949	\$ (38,343)	\$ 585,606	\$ (652)	\$ 31,467	\$ 616,421
2								
3	Weighted Cost of Capital		8.980%	-1.204%	7.776%	0.000%	1.204%	8.980%
4								
5	Return on Rate Base	L 1 * L 3	56,031	(10,493)	45,538	-	379	55,355
6								
7	Income Tax Expense	P 2, L 40	18,999	(4,333)	14,632	(235)	4,333	18,764
8								
9	Total Return and Income Taxes	L 5 + L 7	75,030	(14,826)	60,170	(235)	4,712	74,119
10								
11	Operating Expenses							
12	Operation & Maintenance	P 3, L 26	147,534	(22,184)	125,350	(169)	22,184	147,365
13								
14	Depreciation	P 3, L 28	41,466	(688)	40,778	(9)	688	41,457
15								
16	Amortization	P 3, L 29	686	-	686	-	-	686
17								
18	Taxes Other Than Income Taxes	Pg 3, L 30	24,060	(962)	23,098	(879)	962	23,181
19								
20	Total Operating Expenses	Sum L 12 to L 18	213,746	(23,834)	189,912	(1,057)	23,834	212,689
21								
22	Total Cost of Service	L 9 + L 20	288,776	(38,660)	250,082	(1,292)	28,546	286,808
23								
24	Revenues From Current Rates	P 3, Line 3	223,242	-	223,242	(20)	-	223,222
25								
26								
27	Revenue Deficiency	L 22 - L 24	\$ 65,534	\$ (38,660)	\$ 26,840	\$ (1,272)	\$ 28,546	\$ 63,586

The Narragansett Electric Company d/b/a National Grid
Comparative And Updated Revenue Requirement
For the Twelve Months Ended December 31, 2010

Line #	Description	Reference Or Factor	Rate Base, Return and Taxes (\$ in Thousands)					Company Adjustments		Revised Company Position (f)
			Company As Filed (a)	Division Adjustments (b)	Division As Filed (c)	Updates & Corrections (d)	Rebuttal (e)			
					(a) + (b)					Sum (e) to (f)
RATE BASE										
1	Electric Plant in Service		\$ 1,232,747	\$ (20,222)	\$ 1,212,525	\$ (269)	\$ 20,222	\$	1,232,478	
2	Plant Held for Future Use		204		204				204	
3	Contributions in Aid of Construction		(103)		(103)				(103)	
4	Accumulated Depreciation		(516,525)	(2,397)	(518,922)	(66)	2,397		(516,591)	
5										
6	Net Plant	Sum L 1 to L 4	716,323	(22,619)	693,704	(335)	22,619		715,988	
7										
8	Materials & Supplies		6,376		6,376				6,376	
9	Prepayments		2		2				2	
10	Loss on Reacquired Debt		4,592		4,592				4,592	
11	Cash Working Capital		17,789	(8,848)	8,941	(338)	8,848		17,451	
12	Sub-Total	Sum L 8 to L 11	28,759	(8,848)	19,911	(338)	8,848		28,421	
13										
14	Accumulated Deferred Income Tax		(113,088)	(6,876)	(119,964)	21			(119,943)	
15	Customer Deposits		(3,283)		(3,283)				(3,283)	
16	Injuries & Damages Reserve		(4,762)		(4,762)				(4,762)	
17	Sub-Total	Sum L 14 to L 16	(121,133)	(6,876)	(128,009)	21	-		(127,988)	
18										
19	RATE BASE	L 6 + L 12 + L 17	\$ 623,949	\$ (38,343)	\$ 585,606	\$ (652)	\$ 31,467	\$	616,421	
20										
21	Weighted Cost of Capital		8.980%	-1.204%	7.776%		1.204%		8.980%	
22										
23	After-Tax Return Requirement	L 19 * L 21	56,031	(10,494)	45,537				55,355	
24										
25	Weighted Return on Equity		5.800%		4.806%				5.800%	
26										
27	Equity Return	L 19 * L 25	36,189	(8,045)	28,144				35,752	
28										
29	Flow Thru Items		(1,269)	-	(1,269)				(1,269)	
30										
31	Taxable Income Base	L 29 + L 29	\$ 34,920	\$ (8,045)	\$ 26,875				\$ 34,483	
32										
33	Taxable Income	L 31 / 0.65	\$ 53,723	\$ (12,377)	\$ 41,346				\$ 53,051	
34										
35	Calculated Income Tax	L 33 * 0.35	\$ 18,803	\$ (4,333)	\$ 14,470				\$ 18,568	
36	Rounding		34						34	
37	Unfunded DIT Catch-Up		650		650				650	
38	Amortization of ITC		(488)		(488)				(488)	
39										
40	Total Income Tax Expense	Sum L 35 to L 38	18,999	(4,333)	14,632	(235)	4,333		18,764	
41										
42	Total Return & Income Taxes	L 27 + L 40	\$ 75,030	\$ (14,827)	\$ 60,169	\$ (235)	\$ 4,333	\$	\$ 74,119	

The Narragansett Electric Company d/b/a National Grid
Comparative And Updated Revenue Requirement
For the Twelve Months Ended December 31, 2010

Operating Revenue and Expenses (\$ in Thousands)									
Line #	Description	Reference Or Factor	Company As Filed (a)	Division Adjustments (b)	Division As Filed (c)	Updates & Corrections (d)	Company Adjustments Rebuttal (e)	Revised Company Position (f)	Sum (e) to (e)
OPERATING REVENUES									
1	Distribution Revenue		\$ 215,543	\$ -	\$ 215,543	\$ -	\$ -	\$ 215,543	
2	Other Revenue		7,699	-	7,699	(20)	-	7,679	
3	Total Revenue	L 1 + L 2	<u>\$ 223,242</u>	<u>\$ -</u>	<u>\$ 223,242</u>	<u>\$ (20)</u>	<u>\$ -</u>	<u>\$ 223,222</u>	
OPERATING EXPENSES									
5	Salaries & Wages		\$ 46,372	\$ (1,204)	\$ 45,168		\$ 1,204	\$ 46,372	
6	Contracted Minimum Staffing		1,363	(1,363)	-		1,363	1,363	
7	Customer Assistance Advocacy		182	(182)	-		182	182	
8	Rate Case Expense Amort		865	(519)	346		519	865	
9	Customer Contact Activities		376	(376)	-		376	376	
10	Economic Development Program		1,000	(1,000)	-		1,000	1,000	
11	Vegetation Management Program		8,809	(1,985)	6,824		1,985	8,809	
12	Inspection & Maintenance Program		4,676	(2,094)	2,582		2,094	4,676	
13	Affiliate Charge - GIS in a/c # 583		5,315	(2,300)	3,015		2,300	5,315	
14	Affiliate Charge - Transformation a/c # 588		1,600	(800)	800		800	1,600	
15	Storm Fund Accrual		1,041	(1,041)	-		1,041	1,041	
16	Storm Damage Annual		4,932	(2,001)	2,931	(522)	2,001	4,410	
17	Injuries & Damages		7,055	(2,500)	4,555		2,500	7,055	
18	Legal Fees		1,756	(419)	1,337		419	1,756	
19	ISO Load Research Credit		-	(300)	(300)		300	-	
20	Merger Synergy Savings		2,100	(1,176)	924		1,176	2,100	
21	Uncollectible Expense		5,020	(2,924)	2,096		2,924	5,020	
22	Merger CTC Adjustment		(4,031)		(4,031)	399		(3,632)	
23	Facilities Rent		554		554	(46)		508	
24									
25									
26	Other O&M Expense		58,549		58,549			58,549	
27									
28									
29	Total Operating Expenses	Sum L 6 to L 28	<u>147,534</u>	<u>(22,184)</u>	<u>125,350</u>	<u>(169)</u>	<u>22,184</u>	<u>147,365</u>	
30	Depreciation		41,466	(688)	40,778	(9)	688	41,457	
31	Amortization		686		686			686	
32	Taxes Other Than Income Taxes		24,060	(962)	23,098	(879)	962	23,181	
33	Operating Expenses Before Income Taxes	Sum L 31 to L 33	<u>213,746</u>	<u>(23,834)</u>	<u>189,912</u>	<u>(1,057)</u>	<u>23,834</u>	<u>212,689</u>	
34									
35									
36	Income Tax Expense		18,999	(4,366)	14,633	(235)	4,366	18,764	
37	Total Operating Expenses	L 34 + L 36	<u>\$ 232,745</u>	<u>\$ (28,200)</u>	<u>\$ 204,545</u>	<u>\$ (1,292)</u>	<u>\$ 28,200</u>	<u>\$ 231,453</u>	
38									
39									

Schedule NG-RLO-R-2

Calculation of Uncollectible Rate Using Mr. Gay's Proposal

The Narragansett Electric Company d/b/a National Grid
Calculation of Uncollectible Rate Using Mr. Gay's Proposal

Line #	Description	Reference Or Factor	Mr. Gay Calculations	Adjustments	Mr. Gay Adjusted
		(a)	(b)	(c)	(d)
<u>2008 Gross Charge Offs (Actual)</u>					
1	Standard Residential		\$ 8,747,620	\$ -	\$ 8,747,620
2	Protected Residential		1,341,167		1,341,167
3	Non-Residential		2,788,025		2,788,025
4	Subtotal	L 1 + L 2 + L 3	12,876,812	-	12,876,812
5	2008 CO Recoveries		(463,961)		(463,961)
6	Net Charge Offs	L 4 + L 5	\$ 12,412,851	\$ -	\$ 12,412,851
7	Revenue		\$ 1,065,968,828		\$ 1,065,968,828
8	Charge Off Percent	L 6 / L 7	1.16%		1.16%
<u>Mr. Gay's Recommendation</u>					
9	Standard Residential		\$ (3,618,136)	\$ -	\$ (3,618,136)
10	Protected Residential		n/a		
11	Non-Residential		(1,246,140)		(1,246,140)
12	Subtotal	L 9 + L 10 + L 11	(4,864,276)	-	(4,864,276)
13	2008 CO Recoveries	Line 5	(463,961)	175,261 [a]	(288,700)
14	Net Charge Offs	L 4 + L 12 + L 13	\$ 7,548,575	\$ 175,261	\$ 7,723,836
15	Revenue		\$ 1,065,968,828	\$ (5,427,204) [b]	\$ 1,060,541,624
16	Charge Off Percent	L 14 / L 15	0.71%		0.73%
[a] Reduction in CO Recoveries to match reduction in Charge Offs.					
[b] Reduction in revenue to reflect customers lost from early disconnection					
		Accounts	Month Revenue	# of Months	Revenue Adjust
		5,449	\$83.00	12	\$ 5,427,204

Schedule NG-RLO-R-3

Rate Year Plant in Service and Accumulated Depreciation

The Narragansett Electric Company d/b/a National Grid
Rate Year Plant in Service and Accumulated Depreciation

Period Ended December 31, 2010
(\$ in Thousands)

Line #	Description	Reference Or Factor (a)	Company As Filed (b)	Division Adjustments (c)	Division As Filed (d)	Company Update (e)	Company Revised (f)
UTILITY PLANT							
1	Utility Plant at 12-31-08	NG-RLO-2, P 34	\$ 1,147,926	\$ -	\$ 1,147,926	\$ -	\$ 1,147,926
2	Plant Additions in 2009		59,949	(9,530)	50,419	9,269	59,688
3	Plant Retirements in 2009	13.372%	(8,016)	1,275	(6,741)	(1,240)	(7,981)
4	Net Plant Additions		51,933	(8,255)	43,678	8,029	51,707
5	Utility Plant at 12-31-09		1,199,859	(8,255)	1,191,604	8,029	1,199,633
6	Plant Additions in 2010		75,932	(27,632)	48,300	27,531	75,831
7	Plant Retirements in 2010	13.372%	(10,153)	3,695	(6,458)	(3,681)	(10,140)
8	Net Plant Additions		65,779	(23,937)	41,842	23,850	65,691
9	Utility Plant at 12-31-10		1,265,638	(32,192)	1,233,446	31,878	1,265,324
10	Average Rate Year Balance		\$ 1,232,748	\$ (20,223)	\$ 1,212,525	\$ 19,953	\$ 1,232,478
ACCUMULATED DEPRECIATION							
11	Accumulated Depreciation at 12-31-08	NG-RLO-2, P 35	\$ 477,960	\$ -	\$ 477,960	\$ -	\$ 477,960
12	2009 Depreciation Expense		41,322	(2,854)	38,468	2,849	41,317
13	2009 Plant Retirements	Per above	(8,016)	1,275	(6,741)	(1,240)	(7,981)
14	2009 Cost of Removal	10.618%	(6,365)	1,012	(5,353)	(984)	(6,338)
14	Net Change in Accumulated Depreciation		26,941	(567)	26,374	624	26,998
15	Accumulated Depreciation at 12-31-09		504,901	(567)	504,334	624	504,958
16	2010 Depreciation Expense		41,466	(688)	40,778	678	41,456
17	2010 Plant Retirements	Per above	(10,153)	3,695	(6,458)	(3,681)	(10,140)
18	2010 Cost of Removal	10.618%	(8,062)	2,917	(5,145)	(2,928)	(8,051)
18	Net Change in Accumulated Depreciation		23,250	5,924	29,175	(5,932)	23,265
19	Accumulated Depreciation at 12-31-09		\$ 528,151	\$ 5,358	\$ 533,509	\$ (5,307)	\$ 528,223
20	Average Rate Year Balance		\$ 516,526	\$ 2,396	\$ 518,921	\$ (2,342)	\$ 516,591

REBUTTAL TESTIMONY
OF
HOWARD S. GORMAN

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I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

A. My name is Howard Gorman. I am a Principal Consultant with Black & Veatch Corporation. My business address is 898 Veterans Highway, Hauppauge, NY 11788.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I previously submitted direct testimony on behalf of the Company in its June 1, 2009 filing before the Commission. I also submitted Schedules NG-HSG-1 through 12.

Q. What is the purpose of your rebuttal testimony?

A. In Section II of my rebuttal testimony, I address certain changes proposed by intervenor witnesses to the Allocated Cost of Service Study (“ACOSS”) presented by the Company and the Company’s proposed revenue allocation and rate design. I am responding to portions of the direct testimony of Rhode Island Division of Public Utilities and Carriers (“Division”) witness Swan concerning the following issues:

- A. Allocation among the rate classes of Line Transformer Costs
- B. Allocation among the rate classes of Uncollectible Accounts Expense
- C. Allocation among the rate classes of Customer Service and Information costs
- D. Revenue allocation
- E. Customer charges for rate classes A-16 and C-06

Q. Are you presenting any exhibits today?

A. Yes, I am presenting the following rebuttal schedules:

- Schedule NG-HSG-R-1 ACOSS reflecting certain changes described in Section III

II. CHANGES PROPOSED BY INTERVENOR WITNESSES

A. Allocation of Line Transformer Costs

Q. Did Dr. Swan have any comments about the allocation of the cost of line transformer in the Company's ACOSS?

A. Yes. Dr. Swan said, "Mr. Gorman's allocation of these transformer costs is essentially on the basis of the number of customers in each class that use each of the "standard" transformers. This approach cannot lead to a proper allocation of these costs because it makes no allowance for the different sizes of customers in terms of their loads" (*Swan, p. 10, lines 22-25*).

Q. Is Dr. Swan's statement correct?

A. No. In the ACOSS, the cost of line transformers (Account 368) and maintenance of line transformers (Account 595) were assigned based on a special study of the customers served by each transformer (*Schedule NG-HSG-2, Pages 11-17*). Then, the cost of each transformer was allocated among the rate classes based on the number of customers served by that transformer. Therefore the ACOSS explicitly recognized the 'different sizes of customers in terms of their loads'.

Q. Did Dr. Swan propose an alternative allocation of the cost of line transformer?

A. Yes. Dr. Swan proposes to allocate the cost of individual transformers based on class non-coincident peaks ("NCPs"), using the average of the relative class NCPs at the

1 primary voltage and the secondary voltage (*Swan, p. 12, line 24 – p. 13, line 25*). Dr.

2 Swan claims “there is no direct relationship between the number of transformers and the
3 number of customers” (*Swan, p. 12, lines 11-12*).

4
5 **Q. Do you agree with Dr. Swan’s proposal to allocate Line Transformers based on class**
6 **NCPs?**

7 A. I agree that the cost of the line transformers serving each class depends on both the
8 number of customers and the load size of individual customers. Therefore, I prepared
9 Schedule NG-HSG-R-1, which presents the results of an ACOSS that allocates the cost of
10 line transformers (Account 368) and maintenance of line transformers (account 595) by
11 giving equal (i.e., 50% each) weights to:

- 12 • The allocator developed by Dr. Swan based on “the average of primary and
13 secondary NCP percentage vectors” (*Swan, p. 13, line 14*) and
- 14 • The allocator used in the Company’s ACOSS (developed at *Schedule NG-HSG-2,*
15 *Pages 11-17*)

16
17 **Q. What do you recommend the Commission should do?**

18 A. I recommend that, in evaluating the revenue allocation and rate design, the Commission
19 use the results of the allocated cost of service presented in Schedule NG-HSG-R-1,
20 because it reflects the two factors that affect transformer costs – the number of customers
21 and the load size of individual customers, as well as the dual purpose of the distribution
22 system – to connect customers to the system and to meet peak demands.

1 **B. Allocation among the rate classes of Uncollectible Accounts Expense**

2 **Q. Did Dr. Swan have any comments about the allocation of Uncollectible Accounts**
3 **Expense in the Company's ACOSS?**

4 A. Yes. Dr. Swan said, "Mr. Gorman has allocated these uncollectible costs among the
5 classes in proportion to the class origin of the uncollectible costs. Essentially it amounts
6 to a direct assignment. This strikes me as patently unfair to the residential customers that
7 have paid in a timely fashion." (*Swan, p. 13, lines 18-25*).

8
9 **Q. Did Dr. Swan propose an alternative allocation of Uncollectible Accounts Expense?**

10 A. Yes. Dr. Swan proposes to allocate the Uncollectible Accounts Expense using a "general
11 allocator such as class revenue responsibility" (*Swan, p. 14, line 13*), specifically, the
12 Company's "Total Del Rev" allocator found at Schedule NG-HSG-2, p. 2, line 20. Dr.
13 Swan proposes using this allocation methodology for the allocation of the uncollectible
14 costs associated with both delivery service and commodity service.

15
16 **Q. Do you agree with Dr. Swan's proposal to allocate Uncollectible Accounts Expense**
17 **based on class revenue responsibility?**

18 A. No. As Dr. Swan acknowledges, the Company's allocation of Uncollectible Accounts
19 Expense is essentially a direct assignment, which is normally preferable to an allocation.
20 The 1992 NARUC Electric Utility Cost Allocation Manual (p. 102-103) supports the use
21 of direct assignment to customer classes of Account 904, Uncollectible Accounts, noting
22 that when utilities monitor uncollectible account levels by tariff schedule, direct
23 assignment of these costs is possible and appropriate.

1 The NARUC Manual also offers an alternative allocation methodology based on class
2 revenue responsibility, which Dr. Swan has proposed, as an alternative to the Company's
3 approach for allocating uncollectible costs. However, the Company believes that the
4 collective bad debt expense of all of the customers in a class is an accurate reflection of
5 the cost that the Company incurs to serve that class. It is particularly important that the
6 administrative cost of providing Standard Offer service, including commodity-related bad
7 debt expense, accurately reflect the cost of providing that service for each rate class.
8 Because customers have the option of obtaining commodity supply from competitive
9 suppliers in the market, the Company's Standard Offer administrative charges, including
10 bad debt expense, should be reflective of similar charges available to customers in the
11 market.

12
13 In addition, Rhode Island precedent is direct assignment of Uncollectible Accounts
14 Expense based on historical experience.

15
16 **Q. What do you recommend the Commission should do?**

17 A. I recommend that the Commission accept the allocation of Uncollectible Accounts
18 Expense presented by the Company in its ACOSS and also in Schedule NG-HSG-R-1
19 associated with delivery-related uncollectible accounts, based on cost causation and
20 precedent. If the Commission determines it is more appropriate to allocate delivery-
21 related uncollectible accounts expense based on class revenue responsibility, then the
22 proper allocation basis is the revenue requirement adjusted to include rate year delivery
23 revenue components of: transmission revenue, non-bypassable transition charge revenue,

1 and demand side management revenue, not historical Total Delivery Revenue. However,
2 for commodity-related uncollectible accounts expense, the Company believes the
3 proposal contained in its initial filing is appropriate.
4

5 **C. Allocation among the rate classes of Customer Service and Information costs**

6 **Q. Did Dr. Swan have any comments about the allocation of Customer Service and**
7 **Information costs in the Company's ACOSS?**

8 A. Yes. Dr. Swan said, regarding Accounts 908-910, "None of these cost elements is in any
9 clear way directly caused by the number of customers rather than the amount of service
10 that is provided to the various classes". (*Swan, p. 17, lines 11-12*). In making this
11 observation, he seemed to rely on the definitions provided for the accounts in 18 CFR Ch.
12 I (4-1-04 Edition). He relied on this definition to object to the Company's allocation of
13 these costs among the rate classes in its ACOSS, which was based on a detailed analysis
14 of the costs actually included in Accounts 908-910.
15

16 **Q. Please describe the Customer Service and Information costs in Accounts 908-910.**

17 A. The \$5.4 million Customer Service and Information costs include the following:

- 18 • Approximately \$2.4 million for IS (Information System) support for customers,
19 which is typically allocated based on the number of customers or bills, as the
20 Company did in its ACOSS;
- 21 • \$1 million for the Company's proposed Economic Development Program, which
22 is allocated in the Company's ACOSS among the rate classes to which these
23 programs would be directed;

- 1 • \$700,000 for Customer Service and Information for Commercial and Industrial
- 2 customers, allocated in the Company's ACOSS among those rate classes; and
- 3 • Approximately \$500,000 related to retail access and allocated in the Company's
- 4 ACOSS based on MWh_Meter (which happens to be the same as Dr. Swan's
- 5 proposed general allocator).
- 6

7 **Q. Did Dr. Swan propose an alternative allocation of Customer Service and**
8 **Information costs?**

9 A. Yes. Dr. Swan proposes to allocate the Customer Service and Information costs "on the
10 basis of energy use at the meter" because, as he states, "That strikes me as being
11 consistent with the purpose for which these expenses have been made – the
12 encouragement of safe, efficient and economical use of the utility's service". (*Swan, p.*
13 *18, lines 16-19*).

14

15 **Q. Do you agree with Dr. Swan's proposal to allocate Customer Service and**
16 **Information costs based on energy use at the meter?**

17 A. No. The Company's allocations of these costs reflect cost causation much more closely
18 than Dr. Swan's proposed general allocator.

19

20 **Q. What do you recommend the Commission should do?**

21 A. I recommend that the Commission accept the allocation of Customer Service and
22 Information costs presented by the Company in its ACOSS, which reflects cost causation
23 much more closely than Dr. Swan's proposed general allocator.

D. Revenue Allocation

Q. Did Dr. Swan have any comments about the Company's proposed revenue allocation?

A. Yes. Dr. Swan acknowledged that the Company's proposed revenue allocation moves most of the classes to their full cost of service based on the Company's ACOSS, but proposes the following:

- that the Company's allocated cost of service study be revised to include the adjustments proposed by Dr. Swan and incorporated in the distribution class cost of service study in Schedule DES-1,
- that in measuring rate class impacts, the effects of the Commodity-related Cost Tracker and Transmission Costs rates should be considered, "To properly assess the reasonableness of the proposed class revenue spread, and whether sufficient attention has been paid to rate continuity concerns, the total revenue change for each class needs to be considered" (*Swan, p. 21, lines 2-4*).
- Dr. Swan said, "I find reasonable Mr. Gorman's approach of capping those classes that would otherwise receive very large percentage increases and spreading the shortfall to other classes. However, I believe that the shortfall should be allocated to all other classes whose increases are not capped" (*Swan, p. 22, lines 5-8*).
- that the discount received by rate A-60 customers be recovered from all rate classes, not only rate A-16.

Q. Please discuss Dr. Swan's comments and his revenue allocation proposal.

A. I will address each of Dr. Swan's comments:

- I agree that revenue allocation and rate design should be evaluated based on an ACOSS that reflects the appropriate changes. I recommend that the Commission evaluate revenue allocation and rate design based on Schedule NG-HSG-R-1, which is discussed in Section III, and if additional changes are required by the Commission, on an ACOSS that reflects those changes.
- Regarding Dr. Swan's belief that the reasonableness of the class revenue allocation should consider the total revenue change for each class, then in addition to including the Commodity-related Cost Tracker and Transmission Costs as Dr. Swan has done in Schedule DES-3, commodity costs should be included as well. The table below shows the effect of the Company's proposed increase on a total bill basis including Commodity costs (estimated for all customers at current Standard Offer Charge).

(\$ 000s)	Total	Residential	Small C&I	General C&I	Large C&I	Lighting	Propulsion
Company Proposed Increase (a)	\$75,287	\$49,646	\$6,209	\$9,668	\$4,533	\$5,105	\$126
Distribution Revenue at Present rates (b)	\$223,242	\$117,770	\$23,985	\$32,841	\$39,447	\$8,983	\$215
Transmission Costs (c)	112,537	45,373	8,839	19,841	37,042	905	536
Commodity Costs (d)	<u>712,120</u>	<u>282,285</u>	<u>51,337</u>	<u>127,471</u>	<u>242,261</u>	<u>6,355</u>	<u>2,410</u>
Total Costs	<u>\$1,047,898</u>	<u>\$445,428</u>	<u>\$84,161</u>	<u>\$180,154</u>	<u>\$318,750</u>	<u>\$16,242</u>	<u>\$3,162</u>
Increase	7.2%	11.1%	7.4%	5.4%	1.4%	31.4%	4.0%
(a) Schedule DES-1, line 6, with corrected General C&I (b) Schedule NG-HSG-4, line 4 (c) Schedule NG-HSG-7, line 5 (d) kWh Deliveries (Schedule NG-HSG-2, p. 8, line 8) X Standard Offer Charge \$0.09293 (Schedule NG-HSG-9)							

1 Using Dr. Swan's suggested total bill basis, the Company's proposed increases
2 for all classes except Lighting are seen to be modest, and reasonably close to the
3 average increase. The larger than average increases for Residential and Lighting,
4 and the smaller than average increases for General C&I, Large C&I and
5 Propulsion, reflect the need to move classes to their full cost of service.

- 6 • Dr. Swan's proposal to recover the shortfall for capped classes (i.e., Lighting and
7 Propulsion) from all other classes would mean a larger increase for Residential
8 customers, which seems at odds with his belief that the Company's proposal
9 causes too much of an increase for those customers. The shortfall for capped
10 classes is \$1.2 million, and increases the revenue for Large C&I only modestly,
11 representing 3.6% of current Distribution revenue and 0.4% of current total
12 revenue including Commodity costs.

- 13 • I agree that the discount received by rate A-60 customers be recovered from all
14 rate classes, not only rate A-16.

15
16 **Q. What do you recommend the Department should do?**

17 A. I recommend that the Commission evaluate revenue allocation and rate design based on
18 Schedule NG-HSG-R-1, which is discussed in Section III, and if additional changes are
19 required by the Commission, on an ACOSS that reflects those changes. I further
20 recommend that the Commission accept the Company's proposed allocation; the
21 opportunity to move most rate classes to full cost of service with only modest subsidies
22 being created is rare, and I believe it would be prudent to take advantage of this

1 opportunity. Finally, I agree that the discount received by rate A-60 customers be
2 recovered from all rate classes, not only rate A-16.
3

4 **E. Customer Charges for Rate Classes A-16 and C-06**

5 **Q. Did Dr. Swan have any comments about the Company's proposed customer**
6 **charges?**

7 A. Yes. Dr. Swan believes that the Company's proposed increases in customer charges for
8 rate classes A-16 and C-06 are too large (*Swan, p. 31, lines 6-7*).
9

10 **Q. Please discuss Dr. Swan's comments regarding the Company's proposed customer**
11 **charge for rate class A-16.**

12 A. The Company proposed to increase the monthly customer charge for rate class A-16 from
13 \$2.75 to \$5.50. While this is a large percentage increase, the proposed customer charge
14 is modest compared to residential customer charges of other electric distribution
15 companies, and is well below the revenue requirement for billing function customer-
16 related costs of \$8.49 per month (*Schedule NG-HSG-1, Page 47, Line 5*). Finally, while I
17 share Dr. Swan's concern about the smallest customers, the Company's rate class A-60 is
18 available for low income customers, and A-60 has no current or proposed customer
19 charge.
20

21 **Q. Please discuss Dr. Swan's comments regarding the Company's proposed customer**
22 **charge for rate class C-06.**

1 A. The Company proposed to increase the monthly customer charge for rate class C-06 from
2 \$6.00 to \$10.00. The proposed customer charge is modest compared to small commercial
3 customer charges of other electric distribution companies, and is well below the revenue
4 requirement for billing function customer-related costs of \$13.33 per month (*Schedule*
5 *NG-HSG-1, Page 47, Line 5*).

6
7 **III. REBUTTAL EXHIBITS**

8 **Q. Please describe Schedule NG-HSG-R-1.**

9 A. Schedule NG-HSG-R-1 presents the results of an ACOSS reflecting the following
10 changes from the Company's original ACOSS:

- 11 • Allocation of Line Transformer Costs and Maintenance of Line
12 Transformers by giving equal weights to the allocator developed by Dr.
13 Swan and the allocator used in the Company's ACOSS.
- 14 • Update individual Line Transformer Costs to include labor and overhead
15 costs; Line Transformer Costs in the Company's original filing include
16 only materials costs, as described in the Company's response to Data
17 Request DIV Data Request 18-2.

18
19 **Q. Did you compare the increase at full cost of service in Schedule NG-HSG-R-1, to the**
20 **Company's originally filed Schedule NG-HSG-1?**

21 A. Yes, Schedule NG-HSG-R-1 compares the following information to the Company's
22 originally filed Schedule NG-HSG-1:

- 23 • Net Operating Income- Schedule NG-HSG-R-1, lines 14 and 15

- 1 • Rate of return at Current Rates- Schedule NG-HSG-R-1, lines 18 and 18A
- 2 • Increase (Decrease) Required- Schedule NG-HSG-R-1, lines 35 and 35A

3

4 The differences for each rate class between Schedule NG-HSG-R-1 and the Company's

5 originally filed Schedule NG-HSG-1 are small.

6

7 IV. **CONCLUSION**

8 Q. **Does this conclude your rebuttal testimony today?**

9 A. Yes.

Schedule NG-HSG-R-1

Rebuttal Allocated Cost of Service Study

Class Cost of Service Study (\$000s)

SUMMARY OF RESULTS

	Total	Residential A16 / A60	Small C&I C6	General C&I G2 / E40	200 kW Demand B32 / G32	3000 kW Demand B62 / G62	Lighting S10 / S14	Propulsion X1
Revenue at Present Rates								
1 Distribution charge revenue	215,420	113,105	23,237	31,707	33,256	5,080	8,834	201
2 Other revenue	7,822	4,665	749	1,134	938	173	149	14
3 Total Revenue	223,242	117,770	23,985	32,841	34,194	5,253	8,983	215
4								
Operating Expenses								
5 Operating Expenses	147,587	80,895	14,635	20,872	18,285	5,001	7,414	486
6 Operating Expenses	41,466	21,340	4,105	6,519	5,533	1,589	2,202	178
7 Depreciation Expense	23,971	12,401	2,392	3,734	3,148	896	1,301	99
8 General Taxes								
9 Operating Expenses	213,024	114,636	21,132	31,124	26,965	7,486	10,917	763
10								
11 Income Before Tax	10,218	3,134	2,853	1,717	7,229	(2,233)	(1,934)	(547)
12 Income Tax Expense (Benefit)	(3,686)	(1,909)	(359)	(572)	(492)	(141)	(197)	(16)
13								
14 Net Operating Income	13,904	5,043	3,212	2,289	7,721	(2,092)	(1,737)	(531)
15 Original Filing	13,904	4,250	2,818	2,953	8,020	(1,939)	(1,683)	(514)
16 Rate Base	623,946	323,550	60,617	96,598	83,272	23,920	33,309	2,681
17								
18 Rate of Return at Current Rates	2.23%	1.56%	5.30%	2.37%	9.27%	(8.74%)	(5.22%)	(19.82%)
18A Original Filing	2.23%	1.29%	4.41%	3.24%	9.92%	(8.55%)	(5.12%)	(20.25%)
19 Relative Rate of Return Current Rates	1.00	0.70	2.38	1.06	4.16	(3.92)	(2.34)	(8.89)
20								
Distribution Revenue Requirement								
21 Distribution charge revenue	280,242	148,896	27,672	41,604	36,038	10,188	14,772	1,070
22 Additional M01 revenue	37	19	4	6	5	1	1	0
23 Forfeited discounts	2,901	2,279	221	227	174	0	1	0
24 Other revenue	5,592	2,913	579	960	804	173	148	14
25								
26 Distribution Revenue Requirement	288,772	154,108	28,476	42,797	37,022	10,362	14,923	1,085
27								
28 Operating Expenses	213,024	114,636	21,132	31,124	26,965	7,486	10,917	763
29 Additional uncollectibles expense	719	565	55	56	43	0	0	0
30 Income Before Tax	75,029	38,907	7,289	11,616	10,013	2,876	4,005	322
31 Income Tax Expense	18,999	9,852	1,846	2,941	2,536	728	1,014	82
32 Net Operating Income	56,030	29,055	5,443	8,675	7,478	2,148	2,991	241
33 Rate of Return	8.98%	8.98%	8.98%	8.98%	8.98%	8.98%	8.98%	8.98%
34								
35 Increase (Decrease) Required \$	65,530	36,338	4,491	9,955	2,827	5,109	5,940	870
35A Original Filing	65,530	37,949	5,292	8,607	2,220	4,799	5,830	834
36 Increase (Decrease) Required %	29.4%	30.9%	18.7%	30.3%	8.3%	97.3%	66.1%	403.9%