COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Petition of NSTAR Electric Company and	)	
Western Massachusetts Electric Company, each	)	
d/b/a Eversource Energy for Approval of	)	**D.P.U. 17-05**
an Increase in Base Distribution Rates for Electric	)	
Service Pursuant to G.L. c. 164, §94 and	)	
220 C.M.R. §5.00	)	

DIRECT TESTIMONY OF

PAUL L. CHERNICK

ON BEHALF OF

THE CAPE LIGHT COMPACT

APRIL 27, 2017

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I. IDENTIFICATION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Paul L. Chernick. My business address is 5 Water St., Arlington, Massachusetts.

Q. What is your occupation?

A. I am the president of Resource Insight, Inc.

Q. Please summarize your professional experience.

A. I received a Bachelor of Science degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and a Master of Science degree from the Massachusetts Institute of Technology in February 1978 in technology and policy.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of pro-spective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My resume is included as Exhibit CLC-PLC-2.

Q. Have you testified previously in utility proceedings?

A. Yes, I have. I have testified approximately 300 times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in 35 states and six Canadian provinces. A summary of my prior testimony is included as Exhibit CLC-PLC-2 at 11-53.

Q: Have you previously testified before this Department?

A. Yes. I have testified before the Department of Public Utilities (the "Department") in approximately 50 proceedings, starting in 1978 and including the following recent proceedings:

- DPU 10-131, on a proposed NStar transmission line to Cape Cod.
- DPU 10-54, on the economics of National Grid's long-term purchase of energy from Cape Wind.
- DPU 09-30, on National Grid's proposed revenue-decoupling mechanism and automatic rate adjustments.
- DTE 04-65, on Cambridge's purchase of its streetlights from Cambridge Electric.
- DTE 01-56, on allocation of Berkshire Gas Company's gas costs by load shape and season.

I have testified before the Department on behalf of the Attorney General, the Division of Energy Resources, Boston Gas, the Cape Light Compact (the "Compact"), environmental advocates, a powerplant developer, and various municipalities.

II. INTRODUCTION

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

A. I am testifying on behalf of the Compact in this proceeding.

Q. What is the purpose of your testimony?

A. I address aspects of Eversource's proposed performance-based ratemaking ("PBR") mechanism ("PBRM").

Q. What materials submitted by NSTAR Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy ("Eversource") did you review in order to prepare your testimony?

A. I reviewed the ten-volume filing entitled NSTAR Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy, Petition for Approval of a Performance-Based Ratemaking Mechanism and General Distribution Revenue Change, DPU 17-05, and dated January 17, 2017 (the "Initial Filing"). Specifically, I focused on Volume 2 of the Initial Filing, especially the following exhibits:

- Exhibit ES-PBRM-1, the direct testimony of Mark E. Meitzen.
- Exhibit ES-CAH-1, the direct testimony of Craig A. Hallstrom.
- Exhibit ES-GWPP-1, the direct testimony of Craig A. Hallstrom, Penelope M. Conner, and Douglas P. Horton (the "HCH Panel").

I have also reviewed Eversource's responses, including associated attachments, to the following information requests:

- DPU Set 5
- DPU Set 19
- DPU Set 24
- AG Set 18
- AG Set 21

- AG Set 28
- AG Set 33

Q. Did you review any other materials in preparing this testimony?

A. I reviewed the Department's order in DPU 09-39 and various reports on PBR practice.

Q. How is your testimony organized?

A. My testimony is organized into six sections. In Section III, I describe Eversource's proposed PBRM and Eversource's rationale for that mechanism. In Section IV, I discuss the underlying flaws in Eversource's argument for the PBRM. Section V describes an alternative approach for addressing the purposes that Eversource ascribes to its proposed PBRM. Section VI summarizes my conclusions and recommendations.

Q. Please summarize your overall impression of Eversource's PBR proposal.

A. Eversource's proposed PBRM consists primarily of a mechanism for automatically increasing the revenue decoupling target. While Eversource asserts that these automatic increases in the revenue target would avoid the need for a capital-cost recovery mechanism, Eversource has failed to provide any valid justification for either a capital-cost recovery mechanism or its PBRM proposal. Viewed on its own merits, the PBRM proposal would impose undue costs on customers. In particular, the decoupling revenue cap should not be escalated at more than the rate of general inflation.

III. EVERSOURCE'S PROPOSAL

A. STRUCTURE OF EVERSOURCE'S PROPOSED PBRM

Q. Please summarize Eversource's proposed PBRM.

A. Eversource is requesting Department approval to "implement PBRM that would adjust rates annually in accordance with a revenue-cap formula."[1] (Initial Filing, Vol. 2, Exh. ES-PBRM-1 at 4.) The PBRM adjustment would increase the revenue target in the revenue decoupling mechanism ("RDM") that Eversource proposes in this proceeding. (Initial Filing, Vol. 2, Exh. ES-PBRM-1 at 6.) The proposed PBRM has the following features:

- The revenue target under the revenue decoupling mechanism would increase each year at 2.56% percentage points above the inflation rate, as measured by Gross Domestic Product Price Index 1 ("GDP-PI"), to reflect an assumed degradation of productivity by 1.37% annually and real increases in input prices of 1.19%.
- Eversource would not decrease its revenue in the event of low or negative inflation. The formula would use a minimum inflation rate of 1%, regardless of actual price changes.
- Eversource would agree not to recover the first $400 million in grid-modernization investments until its next rate case, but would be allowed to recover any grid-modernization costs in excess of the $400 million allowance. Eversource describes this as a "stretch factor." (Initial Filing, Vol. 2, Exh. ES-GWPP-1 at 43.)
- The decoupling and PBR mechanisms would continue until Eversource files a new rate case.
- No new performance requirements, incentives or penalties would be added to the PBRM.

Q. What is the significance of the escalation rates built into Eversource's proposed PBRM?

A. If GDP inflation is 2%, which appears to be a reasonable expectation, the GDP-PI would rise 10.4% over five years, while the Eversource revenue target would rise

[1] While Eversource refers to the revenue target as a "revenue cap," that is not an accurate description, since revenues will be reconciled to the target, whether that reconciliation credits ratepayers or (more likely) Eversource.

25%. Starting with the revenues in Exhibits ES-ACOS-2 and ES-ACOS-6 (Initial Filing, Vol. 2), the increase in rates over five years would be $103 million at the inflation rate and $247 million under Eversource's formula; costs flowing through the various riders could increase these values.

B. EVERSOURCE'S RATIONALE FOR ITS PROPOSAL

Q. What is Eversource's justification for proposing that the revenue target under decoupling be adjusted upward every year as provided in its proposed PBRM?

A. Eversource provides the following justifications:

- The PBR adjustment is needed to make up for the fact that decoupling would deny Eversource an increase in revenues due to sales growth. (Initial Filing, Vol. 2, Exh. ES-PBRM-1 at 16.)
- Without the PBR adjustment, Eversource would need to add a mechanism to recover growing capital costs between rate cases.
- The PBR adjustment would offset the costs of serving additional customers.
- Eversource would not need to file rate cases as often because the additional revenues from the growing revenue target would be sufficient to meet Eversource's earnings goals. Eversource suggests that less frequent rate cases would reduce costs, which could result in "more efficient operation" or "more productive activities."[2] (Initial Filing, Vol. 2, Exh. ES-PBRM-1 at 24.)

Q. What specific claims does Eversource make regarding the need for the PBRM to offset the loss of sales growth?

A. Mr. Meitzen explains his view of the problem as follows:

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[2] Eversource would not be under any obligation to redirect its savings from reduced regulation to improve efficiency or productivity.

> The RDM does not recover any more or less than the previously identified distribution revenue target; therefore, if costs have increased, there is…no sales growth available to the utility to offset those costs.

(Initial Filing, Vol. 2, Exh. ES-PBRM-1 at 16.) He also quotes the Department's observation that:

> Between rate cases, distribution companies have the opportunity to use the increase in revenues from sales growth to pay for, among other things, increasing O&M costs, as well as to fund system reliability and capital expansion projects. With the implementation of revenue decoupling, revenue from growth in usage per customer would be eliminated.

(DPU 07-50-A Order at 48 (July 16, 2008).)

The HCH Panel witnesses similarly claim that:

> [W]ith the implementation of revenue decoupling and the loss of sales-growth revenues, the Company needs to establish a ratemaking mechanism to produce a level of revenues to offset the impact of operating costs and capital investment between rate cases.

(Initial Filing, Vol. 2, Exh. ES-GWPP-1 at 20.) The HCH Panel also asserts that decoupling deprives Eversource of revenue growth:

> [T]he first annual PBR adjustment would have to be January 1, 2019 instead of January 1, 2018, leaving a full year impact with revenue decoupling in place and no revenue mechanism to replace revenues subsumed by the revenue decoupling mechanism.

(Resp. to DPU 19-2.)

Mr. Horton similarly describes "[t]he Department's practice [of implementing] a complementary ratemaking mechanism such as the capital cost recovery mechanism" as being intended "to alleviate the negative impact of lost sales revenues due to revenue decoupling." (Resp. to DPU 21-2.)

Q. What does Eversource say about the need for the automatic rate increases in the PBRM as a substitute for a capital-cost recovery mechanism?

A. Mr. Hallstrom simply asserts that "[t]he PBRM would substitute for a capital-cost recovery mechanism" (Initial Filing, Vol. 2, Exh. ES-CAH-1 at 7), as does Mr. Meitzen (Initial Filing, Vol. 2, Exh. ES-PBRM-1 at 4 and 18), who also asserts that:

> the Eversource Grid-Wise Performance Plan, including the PBRM and GMBC, will constitute a more efficient regulatory approach, obviating the need for two capital cost recovery mechanisms, thus reducing regulatory and administrative costs without eliminating the benefit of the plan.[3]

(Initial Filing, Vol. 2, Exh. ES-PBRM-1 at 18.)

Q. Where does Eversource argue that the PBRM is required to recover the costs of serving an increasing number of customers?

A. Mr. Meitzen makes this claim in the following passage, in which he misstates the RDM decoupling target as if it were a cap:[4]

> [U]nder a revenue cap as Eversource is proposing, the cap is not adjusted for customer growth. Therefore, if the firm experiences growth in its customers, this amounts to an implicit [consumer productivity dividend] under a revenue cap. For example, over the 2001-2015 period, NSTAR Electric experienced average annual customer growth of 0.61% and WMECO had average annual customer growth of 0.30%, for an overall weighted average of 0.56%. A revenue cap would not account for this customer growth and, therefore, the additional costs associated with this growth would be absorbed by the Company.

(Initial Filing, Vol. 2, Exh. ES-PBRM-1 at 59.)

IV. PROBLEMS WITH EVERSOURCE'S PBR PROPOSAL

Q. What categories of problems with Eversource's PBR proposal have you identified?

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[3] Mr. Meitzen's reference to "two capital-cost recovery mechanisms" apparently assumes that Eversource would need separate mechanisms for the grid modernization and other capital costs.

[4] As I explain in footnote 1, the revenue target is more likely to act as a floor on revenues than as a cap.

A. The problems break down into two categories:

1. The justifications that Eversource advances for its PBRM do not hold up to scrutiny.
2. The specific proposal has several serious flaws.

A. THE INADEQUATE RATIONALE FOR THE EVERSOURCE PBRM PROPOSAL

Q. Please identify the areas where Eversource's rationale for its PBR proposal does not withstand scrutiny.

A. Eversource fails to provide any support that its PBR proposal is needed for either of two reasons that Eversource advances: (1) that the PBRM is necessary to compensate Eversource for giving up revenue from sales growth during decoupling; and (2) that Eversource requires a PBRM to reduce the frequency of rate cases.

Q. Regarding the first rationale, is Eversource correct that the PBRM is needed to compensate Eversource for giving up the revenue from sales growth during the period in which decoupling freezes the revenue target?

A. No. Eversource's Massachusetts operating companies have been experiencing negative sales growth since 2005. As I discuss below, there is no reason to expect that will change for many years.

Q. Does Eversource acknowledge that its sales growth has been negative?

A. Yes, even though Eversource claims to be concerned about losing the benefits of sales growth, the HCH Panel recognizes that sales have fallen over the last nine years:

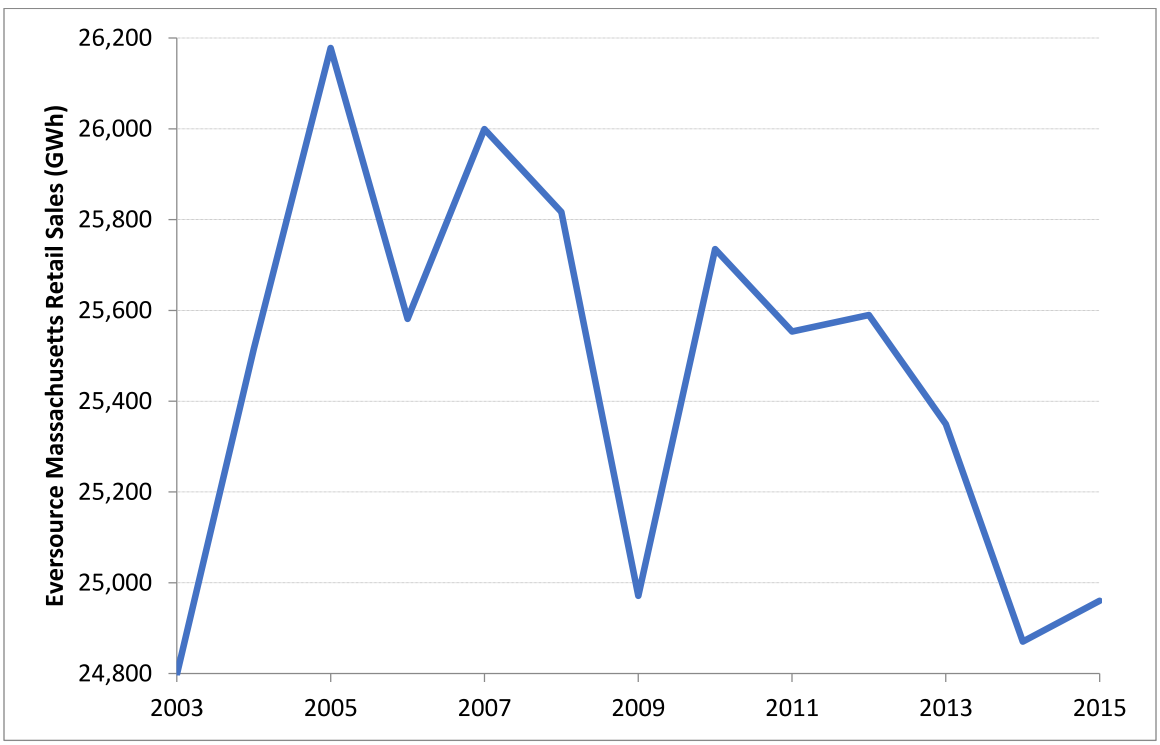
> [S]ince 2008 the compounded annual growth rate in total sales has reversed…to -0.6 percent in the period 2008-2016 in the NSTAR Electric service area, representing a cumulative reduction of approximately 1,029 gigawatthours ("GWH"), since 2008.

> Similarly, in Eversource's western service area the compounded annual growth rate in total sales [was] -1.0 percent in the period 2008-2016, representing a cumulative reduction of approximately 283 GWH, since 2008.

(Initial Filing, Vol. 2, Exh. ES-GWPP-1 at 28.)

Figure 1 shows the total Massachusetts sales by the Eversource utilities, by year, from data in the Energy Information Administration Form 861 summaries.[5] Sales have fallen fairly steadily with some year-to-year variability and a big dip in 2009 during the Great Recession.

Figure 1: History of Eversource Retail Electric Utility Sales



Far from "subsuming" Eversource revenues from sales growth, decoupling would protect Eversource from losing revenues as sales decline.

Q. Is this pattern of declining sales likely to continue?

[5] https://www.eia.gov/electricity/data/eia861/.

A. Yes. The Department-approved efficiency goals for Eversource and the Compact total about 720 gigawatt-hours ("GWh") annually in 2017 and 2018, resulting in a combined sales decrease in those two years comparable to the combined decline in the previous eight years. (DPU 15-160 – 15-169 Order, Table 3 at 156 (January 28, 2016).). Since Eversource reports sales of about 23,972 GWh (Initial Filing, Vol. 2, Sch. RDP-2 (East) and Sch. RDP-2 (West) at 1), the annual efficiency improvements are about 3% of Eversource sales. Additional behind-the-meter generation and net metering will further reduce Eversource sales. Eversource has cited rapid growth in distributed generation in its justification of its Grid Modernization Base Commitment ("GMBC"). The GMBC is discussed in the testimony of Compact witness, Karl R. Rábago, in Exhibit CLC-KRR-1.

Even Eversource recognizes that this trend will continue. Figure ES-GWPP-2 shows falling Eversource Massachusetts sales through 2022. This trend is unlikely to reverse for many years.

Decoupling will thus become an even more important benefit to Eversource in the future, as sales continue to decline. Since decoupling is a benefit to Eversource, there is no justification for any ratemaking provisions to compensate Eversource for adopting decoupling.

Q. Is this downward trend in sales offset by increases in customer count?

A. No. As I noted above, Eversource reports average growth in customer number of just 0.56%. (Initial Filing, Vol. 2, Exh. ES-PBRM-1 at 59.) This is slightly less than the average rate of decline in Eversource Massachusetts since 2008 (Initial Filing, Vol. 2, Exh. ES-GWPP-1 at 28), and about a sixth of the 3% energy savings targets in 2017 and 2018. So even if the customer charges produced the same revenue as the usage charge, falling sales would outweigh the revenues from new customers.

In addition, customer charge revenues are much smaller than usage-related revenues, as shown in Table 1 for Eversource's 2015/16 test year.[6]

Table 1: Eversource Revenue by Billing Determinant

	Customer	Energy	Demand	Total
WMECo	$28,863,581	$61,839,298	$37,330,069	$128,032,947
	22.5%	48.3%	29.2%	
NStar	$97,271,871	$403,737,679	$321,777,869	$822,787,419
	11.8%	49.1%	39.1%	
Total	$126,135,452	$465,576,977	$359,107,938	$950,820,366
	13.3%	49.0%	37.8%	

Source: Sch. RDP-1, Attachments DPU-5-1c and 5-1d

Proposed energy revenues exceed proposed customer-charge revenues by a factor of nearly four.[7] Even if the recent and future decline in energy sales were similar to the rise in customer number in percentage terms, the revenue effects of declining sales would eclipse that of growth in customer number. Since the percentage decline in sales is much faster than the rise in customer number, the change in sales is all the more dominant.

Many, and perhaps most, energy-efficiency measures will reduce demand charges in addition to energy charges, so falling sales have undoubtedly eroded demand charges as well. Eversource's total base revenues have been falling over time, not growing, and decoupling would help Eversource by halting that fall.

[6] This analysis does not include streetlighting revenues.

[7] This result would not change substantially with Eversource's proposed rate design.

Even considering the growth in revenue due to customer number, Eversource could not expect to see growth in revenues in the absence of decoupling. The proposed PBRM cannot be justified as compensation for lost revenue growth.

Q. Regarding Eversource's second rationale for its PBR proposal, is a PBRM necessary to reduce the frequency of Eversource rate cases?

A. No. Eversource has not had frequent rate cases, even when it was experiencing falling sales without a decoupling mechanism and had no PBRM to increase its base revenues every year. Prior to the current filing, the previous rate filings were six years ago for Western Massachusetts Electric (in DPU 10-70) and twelve years ago for NSTAR Electric (in the DTE 05-85 settlement).[8]

If anything, Eversource should be filing base-rate cases more frequently than its utilities have in the past, not less frequently. Eversource certainly cannot justify a PBR proposal based on frequency of its prior rate cases.

B. Other Problems In the PBRM Proposal

Q. In the previous section, you demonstrated that Eversource's rationales for its PBR proposal have no validity. Are there other problems with the PBR proposal?

A. Yes. I have identified five other problems with the PBRM proposal. Even if the Department found some reason to adopt some portion of the Eversource proposal, it would still be unacceptable unless the Department corrected these problems:

1. Eversource inappropriately proposes that the PBR be structured to build in continuing degradation in the efficiency of its operations.

[8] NStar had a mechanism that increased rates by less than inflation from 2006 to 2012, without adjusting for the decline in sales.

2. Eversource proposes that the decoupling mechanism and the associated revisions to the revenue target run until Eversource decides to file a rate case or is required to by law.

3. While Eversource offers to defer recovery of the first $400 million of grid-modification investments until its next rate proceeding, it does not define the process by which those investments will be segregated from other investments.

4. Eversource has not adequately justified its request for a 1% floor on the inflation rate used at the base for escalating the decoupling revenue target.

5. The Department should review the performance metrics and incentives associated with any automatic rate adjustment to ensure that Eversource has adequate incentives to improve performance, including its performance as a partner with municipalities and other government entities.

Q. Regarding the first problem, please elaborate on Eversource's proposal to build into the PBR an assumed decline in its efficiency.

A. Eversource requests that the revenue target rise, not at general inflation, but 2.56 percentage points above inflation, or *i*+2.56%. This value assumes that Eversource will need more resources every year to provide the same output and that the cost of those resources will increase faster than the general rate of inflation.

This request is a break from traditional PBR plans, in which the revenue cap rises at less than inflation. A survey by Makholm, et al. (attached as Exhibit CLC-PLC-3), shows that the PBR plans of North American distribution utilities with decoupling had revenue caps ranging from at 0.3% *below* inflation to more than 2% *below* inflation. The settlement in DTE 05-85 provided for base rates to increase at 0.5% to 0.75% *below* inflation for 2007 through 2012, offset by reductions in transition charges. (DTE 05-85 Order at 4 (December 30, 2005).) The Department set the escalator for National Grid at 0% (DPU 09-39).

Of the 2.56% annual adder to inflation that Eversource requests, 1.37% is attributed to declining productivity that Mr. Meitzen claims to have found in his sample of the U.S. electric utility industry.[9]

Q. Is it appropriate to build into a PBR revenue increases at higher than the rate of inflation?

A. No. PBR has generally been structured to share the benefits of improving utility efficiency. Mr. Meitzen claims that the costs of the inputs to electric distribution have been increasing and the productivity of the utilities has been decreasing. (Initial Filing, Vol. 2, Exh. ES-PBRM-1 at 52.) If the Department finds that Mr. Meitzen is incorrect and that Eversource is likely to be able to improve productivity and keep cost growth below inflation, the Department can establish a mechanism that adjusts the decoupling target to share those improvements.

On the other hand, if Mr. Meitzen is correct that utility costs have been rising and utility productivity has been falling, and if those conditions are likely to persist, the Department should not approve a PBR plan incorporating automatic increases in the revenue cap, but should instead require that Eversource file a rate case when it needs to increase revenue. Once conditions return to normal, and there are productivity gains to be shared, the Department could then consider an indexed revenue cap once more.

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[9] I will not comment on Mr. Meitzen's derivation of this productivity factor, other than to note that: (1) this is not his estimate of the rate of productivity decline in the utility industry (which is about 0.46%), but the difference between that value and the industry-wide productivity trend; (2) his estimate measures distribution output in terms of the number of customers served; (3) analysts of productivity trends use a variety of output measures and methodologies; and (4) Mr. Meitzen has changed his methodology since his filing in an Alberta PBR case in March 2016, in which he used energy, not customer number, as the measure of output (Alberta Public Utilities Commission ("PUC"), Decision 20414-D01-2016 at 24 (February 6, 2017)). Interestingly, Mr. Meitzen's recommendation in Alberta (an annual adjustment 1.11% above inflation) was rejected by the Alberta PUC, in favor of an adjustment of 0.3% below inflation. (*Id.* at 45.)

Q. Regarding the second issue, how long should the decoupling process, including any PBR adjustments, run before it is reviewed ?

A. For the first round of Eversource decoupling, I recommend that the Department require that rates be reviewed and reset after it has about three years of experience with the mechanism. The Department should at that point reassess Eversource's revenue requirements, reset the decoupling revenue target and review the mechanism's operation, such as the formula for adjusting the revenue target and the operation of performance incentives. Once the Department has more experience with the decoupling mechanism, it may decide to extend subsequent periods, to as much as five years, which I understand to be the legal limit for the interval between rate proceedings.

Q. Regarding the third issue, has Eversource adequately defined its proposed treatment of grid-modification investments?

A. No. Eversource has not explained how it would distinguish between the grid-modernization expenditures and the expenditures that occur in the normal course of business, such as replacing failing equipment and relocating facilities to accommodate transportation and other public projects. Under Eversource's proposal, if Eversource overstates the portion of future expenditures that are related to grid modernization, it may flow costs through an adjustment rider, even though it has not reached the $400 million threshold in incremental grid-modification investments.

In addition, while Eversource has proposed a threshold for the grid modernization flow-through in terms of total investment, the actual revenue requirements would include operation and maintenance expenses, amortization, return, taxes and depreciation depending on the nature of the actual expenditures, such as the split between capital and expenses, and the depreciation life of the capital investment. The burden on Eversource shareholders from delayed recovery of the first $400 million in grid-modification expenditures will depend on the mix of expenditures. Similarly, the revenue requirements of any expenditures over $400 million will depend on which expenditures Eversource includes in the first $400 million and which are designated as excess.[10]

Q. Regarding the fourth issue, has Eversource adequately justified its proposal of a 1% inflation floor?

A. No. Eversource says it set the 1% floor on inflation to allow it to offset five years of absorbing the carrying costs of grid-modernization investments.

> If inflation were to fall below one percent, the PBRM would not produce the level of revenues necessary to support both traditional capital investments and the GMBC; therefore, the floor is necessary to enable the GMBC without a separate cost recovery mechanism.

(Resp. to AG 21-2c.)

> A one percent floor is a necessary component of the PBRM because of the financial commitment the Company is making to spend an incremental $400 million in capital on its Grid Modernization Base Commitment ("GMBC") as part of the Grid Wise Performance Plan ("GWPP").

(Resp. to AG 21-2d.)

Eversource says that there "are no worksheets associated with the decision to propose a one percent floor on inflation" (Resp. to AG 21-2d), but the quotes above suggest that Eversource expects that the 1% floor would compensate for the

[10] The testimony of Karl R. Rábago, Exhibit CLC-KRR-1, discusses the lack of detail and certainty in the GMBC project budgets with respect to spending forecasts, e.g., in his Section V beginning at 28 (discussing storage projects).

carrying costs on the GMBC. In other words, Eversource appears to have structured its PBRM to cover the rate at which it expects to incur costs for the GMBC, as shown in Disc. Attachment AG-21-2 at 2. The compensation to Eversource from the PBRM would be the same, whether or not Eversource expends the funds assumed in Disc. Attachment AG-21-2. If Eversource spends less than it forecast for grid modernization, it pockets the savings. If Eversource expends grid-modernization funds faster than it expects, shareholders would bear the additional carrying charges. Given these incentives, Eversource is unlikely to accelerate grid modernization, even if that would be cost-effective for its customers.

Q. Regarding the fifth problem, do you have any concerns about the performance metrics and incentives associated with the PBRM?

A. Yes. PBR is, by definition, oriented to improving performance. While the PBR mechanism will often include some provisions (such as decoupling, adjustments to the revenue target, and flow-through cost trackers) to provide the utility with adequate revenue during the period that the incentives are guiding the utility's performance, the purpose of PBR should be to encourage performance, not just to maintain utility earnings.

Q. Do the Eversource operating companies currently operate under any performance incentives?

A. Yes. In DPU 12-120-C, the Department set Service Quality Guidelines with potential penalties for failing to meet those deadlines. The following measures can affect utility earnings:

- Two measures of system reliability
- Two measures of reliability for chronically underperforming circuits
- Two measures of responses to downed wires

- Service appointments kept as scheduled (to be implemented at some point in the future)[11]
- Customer complaints to the Department
- Customer credit complaints to the Department
- Customer Satisfaction Surveys

(DPU 12-120-C Order, Attachment A at 19 (December 22, 2014) ("Attachment A").)

The maximum penalty for failing all of these standards simultaneously would be 2.5% of the utility's distribution and transmission revenue "collected through the base rates." (Attachment A at 6.) For comparison, Eversource's proposed revision to the decoupling cap would increase base distribution rates by about 4.6% every year.

Q. Has Eversource proposed any additional performance incentives, rewards or penalties in this proceeding?

A. No. In this proceeding, Eversource proposes the following list of customer benefit metrics, without any associated performance incentives and in some cases without any performance benchmarks (Initial Filing, Vol. 2, Exh. ES-GMBC-3 at 1-6):

- Increase in feeders with distribution management system ("DMS") control.
- DMS Functions implemented (power flow, Volt-VAR optimization ("VVO"), auto-reconfiguration).
- Measure average distributed generation application time by type (Simplified, Expedited, Complex, Pre-applications).
- Reduction in the number of voltage complaints on VVO feeders.
- Conduct an evaluation study of VVO impact on annual kWh reduction.

[11] The Department also required a $100 payment directly to customers when the utility does not keep a schedule appointment. (Attachment A at 25.)

- Increase in total number of customer minutes of outage averted by all automation.
- Measure 5-year average in 4 kV underground reliability indices.
- Measure operation/performance of adaptive relays to system events.
- Completion of project-operations evaluation to compare the originally hypothesized functionalities or use case for each facility with the achieved functionalities or use case for each facility.
- Increase in portal usage.
- Customer satisfaction with portal.
- Measure average distributed generation application time by type (Standard, Expedited, Complex, Pre-applications).
- Billing Timeliness for distributed energy resource ("DER") customers.
- Billing Accuracy for DER customers.
- Annually report utilization of electric vehicle ("EV") charging stations separately for Level II chargers and Fast chargers. Measured in annual kWh per port.
- Annually report the percentage of Eversource residential customers within the range of an Eversource "make ready" site constructed as part of the GMBC. Report percentage within 20 mile range and within 40 mile range.
- Annually collect and report available data on plug-in EV adoption and CO_2 emissions reductions.

This list consists of reports and measurements, without any link to ratemaking.

Q. How should the Department treat performance incentives in this proceeding?

A. The Department should not establish any escalation in the decoupling revenue target until it establishes a comprehensive set of performance incentives, including significant penalties for poor performance. That review should take place outside the time constraints of a rate case.

Q. Should the Department add any categories to the performance incentives?

A. Yes. The existing performance incentives (and even Eversource's proposed toothless performance measures) do not reflect the quality of a set of services that Eversource provides to an important group of stakeholders: municipal governments and other public authorities, such as county government and the Massachusetts Department of Transportation. Some measure of Eversource's outcomes in working with these stakeholders should be added to the performance incentive.

Q. Why is a separate performance incentive for Eversource's relationship with these government stakeholders important?

A. These government entities provide important services—including transportation, community planning and economic development—to all of Eversource's customers and to the Commonwealth. Their ability to provide those services is affected by the Eversource's responsiveness in many ways, such as the following:

- Esthetic effects of double poles, leaning poles, bulky overheads facilities, and exterior maintenance of Eversource facilities (such as substations).
- Safety implications of double poles and temporary installations that block public ways, as well as overloaded and leaning poles.
- Coordination of undergrounding in public ways to minimize disruption and damage to road services.
- Communication with municipal authorities regarding the causes of local reliability problems and the schedule for correcting those problems.
- Coordination with government entities in land-use planning, such as the use of temporarily under-utilized Eversource property and the fate of substations that step down 13.8 kV (or 24 kV) distribution to 4 kV to serve areas with older low-voltage systems.[12]

The Department should develop an incentive mechanism that will reward Eversource for communicating with municipal and other governmental authorities

[12] Eversource appears to be gradually upgrading poles to allow elimination of the 4 kV system.

and expediting solutions of the problems that they identify as priorities.[13] That incentive could be based on a survey of relevant authorities, or more objective measures of response time and resolution of questions and disputes. I intend to develop and file an example incentive in the course of this proceeding.

V. ALTERNATIVE PBR APPROACH

Q. Can the Department structure the decoupling mechanism to reflect the costs to Eversource of accommodating customer growth, without an automatic adjustment to the revenue target?

A. Yes. Growth in the number of customers, even in the absence of growth in load, results in capital investments (for meters, service drops, perhaps extension of a feeder to an area previously without service) and continuing expenses (meter reading, meter maintenance, billing, customer service). Before the first decoupling update in 2019, Eversource can develop and the Department can review and approve (or amend) a set of allowances for the customer-related costs. These allowances could comprise a set of annual values for different types of customer additions, such as:

- In an existing facility, requiring only an additional meter, plus expenses, in $/meter/year. This category could be disaggregated by rate class (which determines the type of meter).
- In a newly-connected building, requiring a meter and service drop, plus expenses, in $/meter/year. This category could be disaggregated between single-phase and three-phase connections, and by the capacity of the service drop.

[13] I would include those officials with direct operating responsibilities affected by Eversource operations, such as mayors, selectmen, departments of public utilities and planning boards.

- Each pole and span of distribution line added, in $/span/year. If necessary, this category can be disaggregated by voltage and capacity.
- Capacity of transformers added, in $/kVA/year.

The decoupling filings could be structured to include a table of the number of additions in each category for new customers, the preapproved unit allowance, and the sum of product of the unit additions and unit allowances, net of contributions in aid of construction from the new customers or developers.

Q. How should the grid-modernization expenditures be recovered in the decoupling period?

A. I understand that the Department will, at some point, approve and order Eversource to undertake a specific set of grid-modernization expenditures, once the Department finds that those expenditures are cost-effective. It should be straightforward for Eversource to document when it has made those expenditures, and for Department to include the expenses and carrying costs in the subsequent decoupling update.

VI. CONCLUSION

Q. Please summarize your observations regarding Eversource's PBR proposal.

A. Eversource has not provided any coherent rationale for proposing a ratemaking structure that would automatically increase Eversource's base distribution revenues, particularly at rates much higher than inflation. Decoupling would protect Eversource against falling sales, so the RDM does not require the escalating revenue target to offset loss of some hypothetical growth.

In addition to lacking any coherent justification, the Eversource PBRM proposal has several flaws that would need to be corrected in any future proposal for a PBRM:

- The mechanism should not build in automatic revenue increases at more than the cost of inflation, plus adjustments for additional services, such as incremental customers and Department-ordered innovative programs and investments.
- There should be no floor on the inflation rate in the revenue-target formula, just as there would be no inflation ceiling under the Eversource proposal.
- Any PBR system should include periodic review of rates.
- The provision for flowing through grid modernization over a $400 million threshold does not adequately define how the eligible costs would be defined.
- The PBR is short on performance requirements and lacks any incentive for performance in working with municipalities and other government authorities.

Q. Please summarize your recommendations as to how the Department should dispose of Eversource's PBRM proposals.

A. The Department should reject Eversource's PBR proposal and implement decoupling without any escalation in the decoupling target, and require that Eversource file for a rate review after a few years of experience. The Department should consider modifying the decoupling target to reflect an estimate of the costs of adding customers. If the Department allows Eversource to flow some targeted costs (such as for grid modernization) through a rider, it should carefully define and verify the costs eligible for inclusion in that rider.

Q. Does this conclude your testimony?

A. Yes, it does.

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SUMMARY OF PROFESSIONAL EXPERIENCE

1986–Present **President, Resource Insight, Inc.** Consults and testifies in utility and insurance economics. Reviews utility supply-planning processes and outcomes: assesses prudence of prior power planning investment decisions, identifies excess generating capacity, analyzes effects of power-pool-pricing rules on equity and utility incentives. Reviews electric-utility rate design. Estimates magnitude and cost of future load growth. Designs and evaluates conservation programs for electric, natural-gas, and water utilities, including hook-up charges and conservation cost recovery mechanisms. Determines avoided costs due to cogenerators. Evaluates cogeneration rate risk. Negotiates cogeneration contracts. Reviews management and pricing of district heating systems. Determines fair profit margins for automobile and workers' compensation insurance lines, incorporating reward for risk, return on investments, and tax effects. Determines profitability of transportation services. Advises regulatory commissions in least-cost planning, rate design, and cost allocation.

1981–86 **Research Associate, Analysis and Inference, Inc.** (Consultant, 1980–81). Researched, advised, and testified in various aspects of utility and insurance regulation. Designed self-insurance pool for nuclear decommissioning; estimated probability and cost of insurable events, and rate levels; assessed alternative rate designs. Projected nuclear power plant construction, operation, and decommissioning costs. Assessed reasonableness of earlier estimates of nuclear power plant construction schedules and costs. Reviewed prudence of utility construction decisions. Consulted on utility rate-design issues, including small-power-producer rates; retail natural-gas rates; public-agency electric rates, and comprehensive electric-rate design for a regional power agency. Developed electricity cost allocations between customer classes. Reviewed district-heating-system efficiency. Proposed power-plant performance standards. Analyzed auto-insurance profit requirements. Designed utility-financed, decentralized conservation program. Analyzed cost-effectiveness of transmission lines.

1977–81 **Utility Rate Analyst, Massachusetts Attorney General.** Analyzed utility filings and prepared alternative proposals. Participated in rate negotiations, discovery, cross-examination, and briefing. Provided extensive expert testimony before various regulatory agencies. Topics included demand forecasting, rate design, marginal costs, time-of-use rates, reliability issues, power-pool operations, nuclear-power cost projections, power-plant cost-benefit analysis, energy conservation, and alternative-energy development.

EDUCATION

SM, Technology and Policy Program, Massachusetts Institute of Technology, February 1978.

SB, Civil Engineering Department, Massachusetts Institute of Technology, June 1974.

HONORS

Chi Epsilon (Civil Engineering)

Tau Beta Pi (Engineering)

Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

PUBLICATIONS

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"Rethinking Utility Rate Design—Retail Demand and Energy Charges," Solar Power PV Conference, Boston MA, February 24, 2016.

"Residential Demand Charges - Load Effects, Fairness & Rate Design Implications." Web seminar sponsored by the NixTheFix Forum. September 2015.

"The Value of Demand Reduction Induced Price Effects." With Chris Neme. Web seminar sponsored by the Regulatory Assistance Project. March 2015.

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"Plugging Into a Municipal Light Plant." With Peter Enrich and Ken Barna. Panel presentation as part of the 2004 Annual Meeting of the Massachusetts Municipal Association. January 2004.

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"The Economic and Environmental Benefits of Gas IRP: FERC 636 and Beyond." Presentation as part of the Ohio Office of Energy Efficiency's seminar, "Gas Utility Integrated Resource Planning," April 1994.

"Cost Recovery and Utility Incentives." Day-long presentation as part of the Demand-Side-Management Training Institute's workshop, "DSM for Public Interest Groups," October 1993.

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"DSM Cost Recovery and Rate Impacts." Presentation as part of "Effective DSM Collaborative Processes," a week-long training session for Ohio DSM advocates sponsored by the Ohio Office of Energy Efficiency, August 1993.

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Puerto Rico Energy Commission, Puerto Rico Electric Power Authority, rate design issues, September 2015 to present.

EXPERT TESTIMONY

1. **Mass. EFSC** 78-12/MDPU 19494, Phase I; Boston Edison 1978 forecast; Massachusetts Attorney General. June 12 1978.

   Appliance penetration projections, price elasticity, econometric commercial forecast, peak demand forecast. Joint testimony with Susan C. Geller.

2. **Mass. EFSC** 78-17, Northeast Utilities 1978 forecast; Massachusetts Attorney General. September 29 1978.

   Specification of economic/demographic and industrial models, appliance efficiency, commercial model structure and estimation.

3. **Mass. EFSC** 78-33, Eastern Utilities Associates 1978 forecast; Massachusetts Attorney General. November 27 1978.

   Household size, appliance efficiency, appliance penetration, price elasticity, commercial forecast, industrial trending, peak demand forecast.

4. **Mass. DPU** 19494, Phase II; Boston Edison Company construction program; Massachusetts Attorney General. April 1 1979.

Review of numerous aspects of the 1978 demand forecasts of nine New England electric utilities, constituting 92% of projected regional demand growth, and of the NEPOOL demand forecast. Joint testimony with Susan Geller.

5. **Mass. DPU** 19494, Phase II; Boston Edison Company construction program; Massachusetts Attorney General. April 1 1979.

   Reliability, capacity planning, capability responsibility allocation, customer generation, co-generation rates, reserve margins, operating reserve allocation. Joint testimony with S. Finger.

6. **U.S. ASLB** NRC 50-471, Pilgrim Unit 2; Commonwealth of Massachusetts. June 29 1979.

   Review of the Oak Ridge National Laboratory and NEPOOL demand forecast models; cost-effectiveness of oil displacement; nuclear economics. Joint testimony with Susan Geller.

7. **Mass. DPU** 19845, Boston Edison time-of-use-rate case; Massachusetts Attorney General. December 4 1979. (Not presented)

   Critique of utility marginal cost study and proposed rates; principles of marginal cost principles, cost derivation, and rate design; options for reconciling costs and revenues. Joint testimony with Susan Geller.

8. **Mass. DPU** 20055, petition of Eastern Utilities Associates, New Bedford G. & E., and Fitchburg G. & E. to purchase additional shares of Seabrook Nuclear Plant; Massachusetts Attorney General. January 23 1980.

   Review of demand forecasts of three utilities purchasing Seabrook shares; Seabrook power costs, including construction cost, completion date, capacity factor, O&M expenses, interim replacements, reserves and uncertainties; alternative energy sources, including conservation, cogeneration, rate reform, solar, wood and coal conversion.

9. **Mass. DPU** 20248, petition of Massachusetts Municipal Wholesale Electric Company to purchase additional share of Seabrook Nuclear Plant; Massachusetts Attorney General. June 2 1980.

   Nuclear power costs; update and extension of MDPU 20055 testimony.

10. **Mass. DPU** 200, Massachusetts Electric Company rate case; Massachusetts Attorney General. June 16 1980.

    Rate design; declining blocks, promotional rates, alternative energy, demand charges, demand ratchets; conservation: master metering, storage heating, efficiency standards, restricting resistance heating.

11. **Mass. EFSC** 79-33, Eastern Utilities Associates 1979 forecast; Massachusetts Attorney General. July 16 1980.

Customer projections, consistency issues, appliance efficiency, new appliance types, commercial specifications, industrial data manipulation and trending, sales and resale.

12. **Mass.** DPU 243, Eastern Edison Company rate case; Massachusetts Attorney General. August 19 1980.

    Rate design: declining blocks, promotional rates, alternative energy, master metering.

13. **Texas** PUC 3298, Gulf States Utilities rate case; East Texas Legal Services. August 25 1980.

    Inter-class revenue allocations, including production plant in-service, O&M, CWIP, nuclear fuel in progress, amortization of canceled plant residential rate design; interruptible rates; off-peak rates. Joint testimony with M. B. Meyer.

14. **Mass.** EFSC 79-1, Massachusetts Municipal Wholesale Electric Company Forecast; Massachusetts Attorney General. November 5 1980.

    Cost comparison methodology; nuclear cost estimates; cost of conservation, cogeneration, and solar.

15. **Mass.** DPU 472, recovery of residential conservation-service expenses; Massachusetts Attorney General. December 12 1980.

    Conservation as an energy source; advantages of per-kWh allocation over per-customer-month allocation.

16. **Mass.** DPU 535; regulations to carry out Section 210 of PURPA; Massachusetts Attorney General. January 26 1981 and February 13 1981.

    Filing requirements, certification, qualifying-facility status, extent of coverage, review of contracts; energy rates; capacity rates; extra benefits of qualifying facilities in specific areas; wheeling; standardization of fees and charges.

17. **Mass.** EFSC 80-17, Northeast Utilities 1980 forecast; Massachusetts Attorney General. March 12 1981 (not presented).

    Specification process, employment, electric heating promotion and penetration, commercial sales model, industrial model specification, documentation of price forecasts and wholesale forecast.

18. **Mass.** DPU 558, Western Massachusetts Electric Company rate case; Massachusetts Attorney General. May 1981.

    Rate design including declining blocks, marginal cost conservation impacts, and promotional rates. Conservation, including terms and conditions limiting renewable, cogeneration, small power production; scope of current conservation program; efficient insulation levels; additional conservation opportunities.

19. **Mass.** DPU 1048, Boston Edison plant performance standards; Massachusetts Attorney General. May 7 1982.

Critique of company approach, data, and statistical analysis; description of comparative and absolute approaches to standard-setting; proposals for standards and reporting requirements.

20. **D.C.** PSC FC785, Potomac Electric Power rate case; D.C. People's Counsel. July 29 1982.

Inter-class revenue allocations, including generation, transmission, and distribution plant classification; fuel and O&M classification; distribution and service allocators. Marginal cost estimation, including losses.

21. **N.H.** PSC DE 81-312, Public Service of New Hampshire supply and demand; Conservation Law Foundation et al. October 8 1982.

Conservation program design, ratemaking, and effectiveness. Cost of power from Seabrook nuclear plant, including construction cost and duration, capacity factor, O&M, replacements, insurance, and decommissioning.

22. **Mass. Division of Insurance,** hearing to fix and establish 1983 automobile insurance rates; Massachusetts Attorney General. October 1982.

Profit margin calculations, including methodology, interest rates, surplus flow, tax flows, tax rates, and risk premium.

23. **Ill.** CC 82-0026, Commonwealth Edison rate case; Illinois Attorney General. October 15 1982.

Review of Cost-Benefit Analysis for nuclear plant. Nuclear cost parameters (construction cost, O&M, capital additions, useful like, capacity factor), risks, discount rates, evaluation techniques.

24. **N.M.** PSC 1794, Public Service of New Mexico application for certification; New Mexico Attorney General. May 10 1983.

Review of Cost-Benefit Analysis for transmission line. Review of electricity price forecast, nuclear capacity factors, load forecast. Critique of company ratemaking proposals; development of alternative ratemaking proposal.

25. **Conn.** DPUC 830301, United Illuminating rate case; Connecticut Consumers Counsel. June 17 1983.

Cost of Seabrook nuclear power plants, including construction cost and duration, capacity factor, O&M, capital additions, insurance and decommissioning.

26. **Mass.** DPU 1509, Boston Edison plant performance standards; Massachusetts Attorney General. July 15 1983.

Critique of company approach and statistical analysis; regression model of nuclear capacity factor; proposals for standards and for standard-setting methodologies.

27. **Mass. Division of Insurance,** hearing to fix and establish 1984 automobile-insurance rates; Massachusetts Attorney General. October 1983.

    Profit margin calculations, including methodology, interest rates.

28. **Conn. DPUC** 83-07-15, Connecticut Light and Power rate case; Alloy Foundry. October 3 1983.

    Industrial rate design. Marginal and embedded costs; classification of generation, transmission, and distribution expenses; demand versus energy charges.

29. **Mass. EFSC** 83-24, New England Electric System forecast of electric resources and requirements; Massachusetts Attorney General. November 14 1983, Rebuttal, February 2 1984.

    Need for transmission line. Status of supply plan, especially Seabrook 2. Review of interconnection requirements. Analysis of cost-effectiveness for power transfer, line losses, generation assumptions.

30. **Mich. PSC** U-7775, Detroit Edison Fuel Cost Recovery Plan; Public Interest Research Group in Michigan. February 21 1984.

    Review of proposed performance target for new nuclear power plant. Formulation of alternative proposals.

31. **Mass. DPU** 84-25, Western Massachusetts Electric Company rate case; Massachusetts Attorney General. April 6 1984.

    Need for Millstone 3. Cost of completing and operating unit, cost-effectiveness compared to alternatives, and its effect on rates. Equity and incentive problems created by CWIP. Design of Millstone 3 phase-in proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

32. **Mass. DPU** 84-49 and 84-50, Fitchburg Gas & Electric financing case; Massachusetts Attorney General. April 13 1984.

    Cost of completing and operating Seabrook nuclear units. Probability of completing Seabrook 2. Recommendations regarding FG&E and MDPU actions with respect to Seabrook.

33. **Mich. PSC** U-7785, Consumers Power fuel-cost-recovery plan; Public Interest Research Group in Michigan. April 16 1984.

    Review of proposed performance targets for two existing and two new nuclear power plants. Formulation of alternative policy.

34. **FERC** ER81-749-000 and ER82-325-000, Montaup Electric rate cases; Massachusetts Attorney General. April 27 1984.

Prudence of Montaup and Boston Edison in decisions regarding Pilgrim 2 construction: Montaup's decision to participate, the Utilities' failure to review their earlier analyses and assumptions, Montaup's failure to question Edison's decisions, and the utilities' delay in canceling the unit.

35. **Maine PUC** 84-113, Seabrook-1 investigation; Maine Public Advocate. September 13 1984.

    Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate effects. Recommendations regarding utility and PUC actions with respect to Seabrook.

36. **Mass. DPU** 84-145, Fitchburg Gas and Electric rate case; Massachusetts Attorney General. November 6 1984.

    Prudence of Fitchburg and Public Service of New Hampshire in decision regarding Seabrook 2 construction: FGE's decision to participate, the utilities' failure to review their earlier analyses and assumptions, FGE's failure to question PSNH's decisions, and utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

37. **Penn. PUC** R-842651, Pennsylvania Power and Light rate case; Pennsylvania Consumer Advocate. November 1984.

    Need for Susquehanna 2. Cost of operating unit, power output, cost-effectiveness compared to alternatives, and its effect on rates. Design of phase-in and excess capacity proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

38. **N.H. PSC** 84-200, Seabrook Unit-1 investigation; New Hampshire Consumer Advocate. November 15 1984.

    Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate and financial effects.

39. **Mass. Division of Insurance,** hearing to fix and establish 1986 automobile insurance rates; Massachusetts Attorney General. November 1984.

    Profit-margin calculations, including methodology and implementation.

40. **Mass. DPU** 84-152, Seabrook Unit 1 investigation; Massachusetts Attorney General. December 12 1984.

    Cost of completing and operating Seabrook. Probability of completing Seabrook 1. Seabrook capacity factors.

41. **Maine PUC** 84-120; Central Maine Power rate case; Maine PUC Staff. December 11 1984.

Prudence of Central Maine Power and Boston Edison in decisions regarding Pilgrim 2 construction: CMP's decision to participate, the utilities' failure to review their earlier analyses and assumptions, CMP's failure to question Edison's decisions, and the utilities' delay in canceling the unit. Prudence of CMP in the planning and investment in Sears Island nuclear and coal plants. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

42. **Maine PUC** 84-113, Seabrook 2 investigation; Maine PUC Staff. December 14 1984.

Prudence of Maine utilities and Public Service of New Hampshire in decisions regarding Seabrook 2 construction: decisions to participate and to increase ownership share, the utilities' failure to review their earlier analyses and assumptions, failure to question PSNH's decisions, and the utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

43. **Mass. DPU** 1627, Massachusetts Municipal Wholesale Electric Company financing case; Massachusetts Executive Office of Energy Resources. January 14 1985.

Cost of completing and operating Seabrook nuclear unit 1. Cost of conservation and other alternatives to completing Seabrook. Comparison of Seabrook to alternatives.

44. **Vt. PSB** 4936, Millstone 3 costs and in-service date; Vermont Department of Public Service. January 21 1985.

Construction schedule and cost of completing Millstone Unit 3.

45. **Mass. DPU** 84-276, rules governing rates for utility purchases of power from qualifying facilities; Massachusetts Attorney General. March 25 1985 and October 18 1985.

Institutional and technological advantages of Qualifying Facilities. Potential for QF development. Goals of QF rate design. Parity with other power sources. Security requirements. Projecting avoided costs. Capacity credits. Pricing options. Line loss corrections.

46. **Mass. DPU** 85-121, investigation of the Reading Municipal Light Department; Wilmington (Mass.) Chamber of Commerce. November 12 1985.

Calculation on return on investment for municipal utility. Treatment of depreciation and debt for ratemaking. Geographical discrimination in street-lighting rates. Relative size of voluntary payments to Reading and other towns. Surplus and disinvestment. Revenue allocation.

47. **Mass. Division of Insurance,** hearing to fix and establish 1986 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau. November 1985.

    Profit margin calculations, including methodology, implementation, modeling of investment balances, income, and return to shareholders.

48. **N.M.** **PSC** 1833, Phase II; El Paso Electric rate case; New Mexico Attorney General. December 23 1985.

    Nuclear decommissioning fund design. Internal and external funds; risk and return; fund accumulation, recommendations. Interim performance standard for Palo Verde nuclear plant.

49. **Penn.** **PUC** R-850152, Philadelphia Electric rate case; Utility Users Committee and University of Pennsylvania. January 14 1986.

    Limerick-1 rate effects. Capacity benefits, fuel savings, operating costs, capacity factors, and net benefits to ratepayers. Design of phase-in proposals.

50. **Mass.** **DPU** 85-270;, Western Massachusetts Electric rate case; Massachusetts Attorney General. March 19 1986.

    Prudence of Northeast Utilities in generation planning related to Millstone 3 construction: decisions to start and continue construction, failure to reduce ownership share, failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

51. **Penn.** **PUC** R-850290, Philadelphia Electric auxiliary service rates; Albert Einstein Medical Center, University of Pennsylvania, and Amtrak. March 24 1986.

    Review of utility proposals for supplementary and backup rates for small power producers and cogenerators. Load diversity, cost of peaking capacity, value of generation, price signals, and incentives. Formulation of alternative supplementary rate.

52. **N.M.** **PSC** 2004, Public Service of New Mexico Palo Verde issues; New Mexico Attorney General. May 7 1986.

    Recommendations for power-plant performance standards for Palo Verde nuclear units 1, 2, and 3.

53. **Ill.** **CC** 86-0325, Iowa-Illinois Gas and Electric Co. rate investigation; Illinois Office of Public Counsel. August 13 1986.

    Determination of excess capacity based on reliability and economic concerns. Identification of specific units associated with excess capacity. Required reserve margins.

54. **N.M. PSC** 2009, El Paso Electric rate moderation program; New Mexico Attorney General. August 18 1986. (Not presented).

    Prudence of EPE in generation planning related to Palo Verde nuclear construction, including failure to reduce ownership share and failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

    Recommendation for rate-base treatment; proposal of power plant performance standards.

55. **City of Boston Public Improvements Commission,** transfer of Boston Edison district heating steam system to Boston Thermal Corporation; Boston Housing Authority. December 18 1986.

    History and economics of steam system; possible motives of Boston Edison in seeking sale; problems facing Boston Thermal; information and assurances required prior to Commission approval of transfer.

56. **Mass. Division of Insurance,** hearing to fix and establish 1987 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau. December 1986 and January 1987.

    Profit margin calculations, including methodology, implementation, derivation of cash flows, installment income, income tax status, and return to shareholders.

57. **Mass. DPU** 87-19, petition for adjudication of development facilitation program; Hull (Mass.) Municipal Light Plant. January 21 1987.

    Estimation of potential load growth; cost of generation, transmission, and distribution additions. Determination of hook-up charges. Development of residential load estimation procedure reflecting appliance ownership, dwelling size.

58. **N.M. PSC** 2004, Public Service of New Mexico nuclear decommissioning fund; New Mexico Attorney General. February 19 1987.

    Decommissioning cost and likely operating life of nuclear plants. Review of utility funding proposal. Development of alternative proposal. Ratemaking treatment.

59. **Mass. DPU** 86-280, Western Massachusetts Electric rate case; Massachusetts Energy Office. March 9 1987.

    Marginal cost rate design issues. Superiority of long-run marginal cost over short-run marginal cost as basis for rate design. Relationship of Consumer reaction, utility planning process, and regulatory structure to rate design approach. Implementation of short-run and long-run rate designs. Demand versus energy charges, economic development rates, spot pricing.

60. **Mass. Division of Insurance** 87-9, 1987 Workers' Compensation rate filing; State Rating Bureau. May 1987.

    Profit-margin calculations, including methodology, implementation, surplus requirements, investment income, and effects of 1986 Tax Reform Act.

61. **Texas PUC** 6184, economic viability of South Texas Nuclear Plant #2; Committee for Consumer Rate Relief. August 17 1987.

    Nuclear plant operating parameter projections; capacity factor, O&M, capital additions, decommissioning, useful life. STNP-2 cost and schedule projections. Potential for conservation.

62. **Minn. PUC** ER-015/GR-87-223, Minnesota Power rate case; Minnesota Department of Public Service. August 17 1987.

    Excess capacity on MP system; historical, current, and projected. Review of MP planning prudence prior to and during excess; efforts to sell capacity. Cost of excess capacity. Recommendations for ratemaking treatment.

63. **Mass. Division of Insurance** 87-27, 1988 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau. September 2 1987. Rebuttal October 8 1987.

    Underwriting profit margins. Effect of 1986 Tax Reform Act. Biases in calculation of average margins.

64. **Mass. DPU** 88-19, power Sales Contract from Riverside Steam and Electric to Western Massachusetts Electric; Riverside Steam and Electric. November 4 1987.

    Comparison of risk from QF contract and utility avoided-cost sources. Risk of oil dependence. Discounting cash flows to reflect risk.

65. **Mass. Division of Insurance** 87-53, 1987 Workers' Compensation rate refiling; State Rating Bureau. December 14 1987.

    Profit-margin calculations including updating of data, compliance with Commissioner's order, treatment of surplus and risk, interest rate calculation, and investment tax rate calculation.

66. **Mass. Division of Insurance,** 1987 and 1988 automobile insurance remand rates; Massachusetts Attorney General and State Rating Bureau. February 5 1988.

    Underwriting profit margins. Provisions for income taxes on finance charges. Relationships between allowed and achieved margins, between statewide and nationwide data, and between profit allowances and cost projections.

67. **Mass.** DPU 86-36, investigation into the pricing and ratemaking treatment to be afforded new electric generating facilities which are not qualifying facilities; Conservation Law Foundation. May 2 1988.

Cost recovery for utility conservation programs. Compensating for lost revenues. Utility incentive structures.

68. **Mass.** DPU 88-123, petition of Riverside Steam & Electric Company; Riverside Steam and Electric Company. May 18 1988 and November 8 1988.

Estimation of avoided costs of Western Massachusetts Electric Company. Nuclear capacity factor projections and effects on avoided costs. Avoided cost of energy interchange and power plant life extensions. Differences between median and expected oil prices. Salvage value of cogeneration facility. Off-system energy purchase projections. Reconciliation of avoided cost projection.

69. **Mass.** DPU 88-67, Boston Gas Company; Boston Housing Authority. June 17 1988.

Estimation of annual avoidable costs, 1988 to 2005, and levelized avoided costs. Determination of cost recovery and carrying costs for conservation investments. Standards for assessing conservation cost-effectiveness. Evaluation of cost-effectiveness of utility funding of proposed natural gas conservation measures.

70. **R.I.** PUC 1900, Providence Water Supply Board tariff filing; Conservation Law Foundation, Audubon Society of Rhode Island, and League of Women Voters of Rhode Island. June 24 1988.

Estimation of avoidable water supply costs. Determination of costs of water conservation. Conservation cost-benefit analysis.

71. **Mass. Division of Insurance** 88-22, 1989 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau; Profit Issues, August 12 1988, supplemented August 19 1988; Losses and Expenses, September 16 1988.

Underwriting profit margins. Effects of 1986 Tax Reform Act. Taxation of common stocks. Lag in tax payments. Modeling risk and return over time. Treatment of finance charges. Comparison of projected and achieved investment returns.

72. **Vt.** PSB 5270 Module 6, investigation into least-cost investments, energy efficiency, conservation, and the management of demand for energy; Conservation Law Foundation, Vermont Natural Resources Council, and Vermont Public Interest Research Group. September 26 1988.

Cost recovery for utility conservation programs. Compensation of utilities for revenue losses and timing differences. Incentive for utility participation.

73. **Vt. House of Representatives, Natural Resources Committee,** House Act 130; "Economic Analysis of Vermont Yankee Retirement"; Vermont Public Interest Research Group. February 21 1989.

    Projection of capacity factors, operating and maintenance expense, capital additions, overhead, replacement power costs, and net costs of Vermont Yankee.

74. **Mass. DPU** 88-67 Phase II, Boston Gas company conservation program and rate design; Boston Gas Company. March 6 1989.

    Estimation of avoided gas cost; treatment of non-price factors; estimation of externalities; identification of cost-effective conservation.

75. **Vt. PSB** 5270, status conference on conservation and load management policy settlement; Central Vermont Public Service, Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group, and Vermont Department of Public Service. May 1 1989.

    Cost-benefit test for utility conservation programs. Role of externalities. Cost recovery concepts and mechanisms. Resource allocations, cost allocations, and equity considerations. Guidelines for conservation preapproval mechanisms. Incentive mechanisms and recovery of lost revenues.

76. **Boston Housing Authority Court** 05099, Gallivan Boulevard Task Force vs. Boston Housing Authority, et al.; Boston Housing Authority. June 16 1989.

    Effect of master-metering on consumption of natural gas and electricity. Legislative and regulatory mandates regarding conservation.

77. **Mass. DPU** 89-100, Boston Edison rate case; Massachusetts Energy Office. June 30 1989.

    Prudence of BECo's decision to spend $400 million from 1986–88 on returning the Pilgrim nuclear power plant to service. Projections of nuclear capacity factors, O&M, capital additions, and overhead. Review of decommissioning cost, tax effect of abandonment, replacement power cost, and plant useful life estimates. Requirements for prudence and used-and-useful analyses.

78. **Mass. DPU** 88-123, petition of Riverside Steam and Electric Company; Riverside Steam and Electric. July 24 1989. Rebuttal, October 3 1989.

    Reasonableness of Northeast Utilities' 1987 avoided cost estimates. Projections of nuclear capacity factors, economy purchases, and power plant operating life. Treatment of avoidable energy and capacity costs and of off-system sales. Expected versus reference fuel prices.

79. Mass. DPU 89-72, Statewide Towing Association police-ordered towing rates; Massachusetts Automobile Rating Bureau. September 13 1989.

Review of study supporting proposed increase in towing rates. Critique of study sample and methodology. Comparison to competitive rates. Supply of towing services. Effects of joint products and joint sales on profitability of police-ordered towing. Joint testimony with I. Goodman.

80. Vt. PSB 5330, application of Vermont utilities for approval of a firm power and energy contract with Hydro-Quebec; Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group. December 19 1989. Surrebuttal February 6 1990.

Analysis of a proposed 450-MW, 20-year purchase of Hydro-Quebec power by twenty-four Vermont utilities. Comparison to efficiency investment in Vermont, including potential for efficiency savings. Analysis of Vermont electric energy supply. Identification of possible improvements to proposed contract.

Critique of conservation potential analysis. Planning risk of large supply additions. Valuation of environmental externalities.

81. Mass. DPU 89-239, inclusion of externalities in energy-supply planning, acquisition, and dispatch for Massachusetts utilities. December 1989; April 1990; May 1990.

Critique of Division of Energy Resources report on externalities. Methodology for evaluating external costs. Proposed values for environmental and economic externalities of fuel supply and use.

82. California PUC, incorporation of environmental externalities in utility planning and pricing; Coalition of Energy Efficient and Renewable Technologies. February 21 1990.

Approaches for valuing externalities for inclusion in setting power purchase rates. Effect of uncertainty on assessing externality values.

83. Ill. CC 90-0038, proceeding to adopt a least-cost electric-energy plan for Commonwealth Edison Company; City of Chicago. May 25 1990. Joint rebuttal testimony with David Birr, August 14 1990.

Problems in Commonwealth Edison's approach to demand-side management. Potential for cost-effective conservation. Valuing externalities in least-cost planning.

84. Md. PSC 8278, adequacy of Baltimore Gas & Electric's integrated resource plan; Maryland Office of People's Counsel. September 18 1990.

Rationale for demand-side management. BG&E's problems in approach to DSM planning. Potential for cost-effective conservation. Valuation of environmental externalities. Recommendations for short-term DSM program priorities.

85. **Ind. URC,** integrated-resource-planning docket; Indiana Office of Utility Consumer Counselor. November 1 1990.

Integrated resource planning process and methodology, including externalities and screening tools. Incentives, screening, and evaluation of demand-side management. Potential of resource bidding in Indiana.

86. **Mass. DPU** 89-141, 90-73, 90-141, 90-194, 90-270; preliminary review of utility treatment of environmental externalities in October qualifying-facilities filings; Boston Gas Company. November 5 1990.

Generic and specific problems in Massachusetts utilities' RFPs with regard to externality valuation requirements. Recommendations for corrections.

87. **Mass. EFSC** 90-12/90-12A, adequacy of Boston Edison proposal to build combined-cycle plant; Conservation Law Foundation. December 14 1990.

Problems in Boston Edison's treatment of demand-side management, supply option analysis, and resource planning. Recommendations of mitigation options.

88. **Maine PUC** 90-286, adequacy of conservation program of Bangor Hydro Electric; Penobscot River Coalition. February 19 1991.

Role of utility-sponsored DSM in least-cost planning. Bangor Hydro's potential for cost-effective conservation. Problems with Bangor Hydro's assumptions about customer investment in energy efficiency measures.

89. **Va. SCC** PUE900070, Order establishing commission investigation; Southern Environmental Law Center. March 6 1991.

Role of utilities in promoting energy efficiency. Least-cost planning objectives of and resource acquisition guidelines for DSM. Ratemaking considerations for DSM investments.

90. **Mass. DPU** 90-261-A, economics and role of fuel-switching in the DSM program of the Massachusetts Electric Company; Boston Gas Company. April 17 1991.

Role of fuel-switching in utility DSM programs and specifically in Massachusetts Electric's. Establishing comparable avoided costs and comparison of electric and gas system costs. Updated externality values.

91. **Private arbitration,** Massachusetts Refusetech Contractual Request for Adjustment to Service Fee; Massachusetts Refusetech. May 13 1991.

NEPCo rates for power purchases from the New England Solid Waste Compact plant. Fuel price and avoided cost projections vs. realities.

92. Vt. PSB 5491, cost-effectiveness of Central Vermont's commitment to Hydro Quebec purchases; Conservation Law Foundation. July 19 1991.

Changes in load forecasts and resale markets since approval of HQ purchases. Effect of HQ purchase on DSM.

93. S.C. PSC 91-216-E, cost recovery of Duke Power's DSM expenditures; South Carolina Department of Consumer Affairs. Direct, September 13 1991; Surrebuttal October 2 1991.

Problems with conservation plans of Duke Power, including load building, cream skimming, and inappropriate rate designs.

94. Md. PSC 8241 Phase II, review of Baltimore Gas & Electric's avoided costs; Maryland Office of People's Counsel. September 19 1991.

Development of direct avoided costs for DSM. Problems with BG&E's avoided costs and DSM screening. Incorporation of environmental externalities.

95. Bucksport (Maine) Planning Board, AES/Harriman Cove shoreland zoning application; Conservation Law Foundation and Natural Resources Council of Maine. October 1 1991.

New England's power surplus. Costs of bringing AES/Harriman Cove on line to back out existing generation. Alternatives to AES.

96. Mass. DPU 91-131, update of externalities values adopted in Docket 89-239; Boston Gas Company. October 4 1991. Rebuttal, December 13 1991.

Updates on pollutant externality values. Addition of values for chlorofluorocarbons, air toxics, thermal pollution, and oil import premium. Review of state regulatory actions regarding externalities.

97. Fla. PSC 910759, petition of Florida Power Corporation for determination of need for proposed electrical power plant and related facilities; Floridians for Responsible Utility Growth. October 21 1991.

Florida Power's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

98. Fla. PSC 910833-EI, petition of Tampa Electric Company for a determination of need for proposed electrical power plant and related facilities; Floridians for Responsible Utility Growth. October 31 1991.

Tampa Electric's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

99. **Penn.** PUC I-900005, R-901880; investigation into demand-side management by electric utilities; Pennsylvania Energy Office. January 10 1992.

Appropriate cost recovery mechanism for Pennsylvania utilities. Purpose and scope of direct cost recovery, lost revenue recovery, and incentives.

100. **S.C.** PSC 91-606-E, petition of South Carolina Electric and Gas for a certificate of public convenience and necessity for a coal-fired plant; South Carolina Department of Consumer Affairs. January 20 1992.

Justification of plant certification under integrated resource planning. Failures in SCE&G's DSM planning and company potential for demand-side savings.

101. **Mass.** DPU 92-92, adequacy of Boston Edison's street-lighting options; Town of Lexington. June 22 1992.

Efficiency and quality of street-lighting options. Boston Edison's treatment of high-quality street lighting. Corrected rate proposal for the Daylux lamp. Ownership of public street lighting.

102. **S.C.** PSC 92-208-E, integrated-resource plan of Duke Power Company; South Carolina Department of Consumer Affairs. August 4 1992.

Problems with Duke Power's DSM screening process, estimation of avoided cost, DSM program design, and integration of demand-side and supply-side planning.

103. **N.C.** UC E-100 Sub 64, integrated-resource-planning docket; Southern Environmental Law Center. September 29 1992.

General principles of integrated resource planning, DSM screening, and program design. Review of the IRPs of Duke Power Company, Carolina Power & Light Company, and North Carolina Power.

104. **Ont.** EAB Ontario Hydro Demand/Supply Plan Hearings, *Environmental Externalities Valuation and Ontario Hydro's Resource Planning* (3 vols.); Coalition of Environmental Groups. October 1992.

Valuation of environmental externalities from fossil fuel combustion and the nuclear fuel cycle. Application to Ontario Hydro's supply and demand planning.

105. **Texas** PUC 110000, application of Houston Lighting and Power company for a certificate of convenience and necessity for the DuPont Project; Destec Energy, Inc. September 28 1992.

Valuation of environmental externalities from fossil fuel combustion and the application to the evaluation of proposed cogeneration facility.

106. **Maine BEP,** in the matter of the Basin Mills Hydroelectric Project application; Conservation Intervenors. November 16 1992.

Economic and environmental effects of generation by proposed hydro-electric project.

107. **Md. PSC** 8473, review of the power sales agreement of Baltimore Gas and Electric with AES Northside; Maryland Office of People's Counsel. November 16 1992.

Non-price scoring and unquantified benefits; DSM potential as alternative; environmental costs; cost and benefit estimates.

108. **N.C. UC** E-100 Sub 64, analysis and investigation of least cost integrated resource planning in North Carolina; Southern Environmental Law Center. November 18 1992.

Demand-side management cost recovery and incentive mechanisms.

109. **S.C. PSC** 92-209-E, in re Carolina Power & Light Company; South Carolina Department of Consumer Affairs. November 24 1992.

Demand-side-management planning: objectives, process, cost-effectiveness test, comprehensiveness, lost opportunities. Deficiencies in CP&L's portfolio. Need for economic evaluation of load building.

110 **Fla. DER** hearings on the Power Plant Siting Act; Legal Environmental Assistance Foundation. December 1992.

Externality valuation and application in power-plant siting. DSM potential, cost-benefit test, and program designs.

111. **Md. PSC** 8487, Baltimore Gas and Electric Company electric rate case. Direct, January 13 1993; rebuttal, February 4 1993.

Class allocation of production plant and O&M; transmission, distribution, and general plant; administrative and general expenses. Marginal cost and rate design.

112. **Md. PSC** 8179, Approval of amendment no. 2 to Potomac Edison purchase agreement with AES Warrior Run; Maryland Office of People's Counsel. January 29 1993.

Economic analysis of proposed coal-fired cogeneration facility.

113. **Mich. PSC** U-10102, Detroit Edison rate case; Michigan United Conservation Clubs. February 17 1993.

Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

114. **Ohio** PUC 91-635-EL-FOR, 92-312-EL-FOR, 92-1172-EL-ECP; Cincinnati Gas and Electric demand-management programs; City of Cincinnati. April 1993.

Demand-side-management planning, program designs, potential savings, and avoided costs.

115. **Mich.** PSC U-10335, Consumers Power rate case; Michigan United Conservation Clubs. October 1993.

Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

116. **Ill.** CC 92-0268, electric-energy plan for Commonwealth Edison; City of Chicago. Direct, February 1 1994; rebuttal, September 1994.

Cost-effectiveness screening of demand-side management programs and measures; estimates by Commonwealth Edison of costs avoided by DSM and of future cost, capacity, and performance of supply resources.

117. **FERC** 2422 et al., application of James River–New Hampshire Electric, Public Service of New Hampshire, for licensing of hydro power; Conservation Law Foundation; 1993.

Cost-effective energy conservation available to the Public Service of New Hampshire; power-supply options; affidavit.

118. **Vt.** **PSB** 5270-CV-1,-3, and 5686; Central Vermont Public Service fuel-switching and DSM program design, on behalf of the Vermont Department of Public Service. Direct, April 1994; rebuttal, June 1994.

Avoided costs and screening of controlled water-heating measures; risk, rate impacts, participant costs, externalities, space- and water-heating load, benefit-cost tests.

119. **Fla.** PSC 930548-EG–930551-EG, conservation goals for Florida electric utilities; Legal Environmental Assistance Foundation, Inc. April 1994.

Integrated resource planning, avoided costs, rate impacts, analysis of conservation goals of Florida electric utilities.

120. **Vt.** **PSB** 5724, Central Vermont Public Service Corporation rate request; Vermont Department of Public Service. Joint surrebuttal testimony with John Plunkett. August 1994.

Costs avoided by DSM programs; Costs and benefits of deferring DSM programs.

121. **Mass.** **DPU** 94-49, Boston Edison integrated-resource-management plan; Massachusetts Attorney General. August 1994.

Least-cost planning, modeling, and treatment of risk.

122. **Mich. PSC** U-10554, Consumers Power Company DSM program and incentive; Michigan Conservation Clubs. November 1994.

Critique of proposed reductions in DSM programs; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

123. **Mich. PSC** U-10702, Detroit Edison Company cost recovery, on behalf of the Residential Ratepayers Consortium. December 1994.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

124. **N.J. BRC** EM92030359, environmental costs of proposed cogeneration; Freehold Cogeneration Associates. November 1994.

Comparison of potential externalities from the Freehold cogeneration project with that from three coal technologies; support for the study "The Externalities of Four Power Plants."

125. **Mich. PSC** U-10671, Detroit Edison Company DSM programs; Michigan United Conservation Clubs. January 1995.

Critique of proposal to scale back DSM efforts in light of potential for competition. Loss of savings, increase of customer costs, and decrease of competitiveness. Discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

126. **Mich. PSC** U-10710, power-supply-cost-recovery plan of Consumers Power Company; Residential Ratepayers Consortium. January 1995.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

127. **FERC** 2458 and 2572, Bowater–Great Northern Paper hydropower licensing; Conservation Law Foundation. February 1995.

Comments on draft environmental impact statement relating to new licenses for two hydropower projects in Maine. Applicant has not adequately considered how energy conservation can replace energy lost due to habitat-protection or -enhancement measures.

128. **N.C. UC** E-100 Sub 74, Duke Power and Carolina Power & Light avoided costs; Hydro-Electric–Power Producer's Group. February 1995.

Critique and proposed revision of avoided costs offered to small hydro-power producers by Duke Power and Carolina Power and Light.

129. New Orleans City Council UD-92-2A and -2B, least-cost IRP for New Orleans Public Service and Louisiana Power & Light; Alliance for Affordable Energy. Direct, February 1995; rebuttal, April 1995.

Critique of proposal to scale back DSM efforts in light of potential competition.

130. D.C. PSC FC917 II, prudence of DSM expenditures of Potomac Electric Power Company; Potomac Electric Power Company. Rebuttal testimony, February 1995.

Prudence of utility DSM investment; prudence standards for DSM programs of the Potomac Electric Power Company.

131. Ont. Energy Board EBRO 490, DSM cost recovery and lost-revenue–adjustment mechanism for Consumers Gas Company; Green Energy Coalition. April 1995.

Demand-side-management cost recovery. Lost-revenue–adjustment mechanism for Consumers Gas Company.

132. New Orleans City Council CD-85-1, New Orleans Public Service rate increase; Alliance for Affordable Energy. Rebuttal, May 1995.

Allocation of costs and benefits to rate classes.

133. Mass. DPU Docket DPU-95-40, Mass. Electric cost-allocation; Massachusetts Attorney General. June 1995.

Allocation of costs to rate classes. Critique of cost-of-service study. Implications for industry restructuring.

134. Md. PSC 8697, Baltimore Gas & Electric gas rate increase; Maryland Office of People's Counsel. July 1995.

Rate design, cost-of-service study, and revenue allocation.

135. N.C. UC E-2 Sub 669. December 1995.

Need for new capacity. Energy-conservation potential and model programs.

136. Arizona CC U-1933-95-317, Tucson Electric Power rate increase; Residential Utility Consumer Office. January 1996.

Review of proposed rate settlement. Used-and-usefulness of plant. Rate design. DSM potential.

137. Ohio PUC 95-203-EL-FOR; Campaign for an Energy-Efficient Ohio. February 1996

Long-term forecast of Cincinnati Gas and Electric Company, especially its DSM portfolio. Opportunities for further cost-effective DSM savings. Tests of cost effectiveness. Role of DSM in light of industry restructuring; alternatives to traditional utility DSM.

138 **Vt. PSB** 5835, Central Vermont Public Service Company rates; Vermont Department of Public Service. February 1996.

Design of load-management rates of Central Vermont Public Service Company.

139. **Md. PSC** 8720, Washington Gas Light DSM; Maryland Office of People's Counsel. May 1996.

Avoided costs of Washington Gas Light Company; integrated least-cost planning.

140. **Mass. DPU** 96-100, Massachusetts Utilities' Stranded Costs; Massachusetts Attorney General. Oral testimony in support of "estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities," July 1996.

Stranded costs. Calculation of loss or gain. Valuation of utility assets.

141. **Mass. DPU** 96-70, Essex County Gas Company rates; Massachusetts Attorney General. July 1996.

Market-based allocation of gas-supply costs of Essex County Gas Company.

142. **Mass. DPU** 96-60, Fall River Gas Company rates; Massachusetts Attorney General. Direct, July 1996; surrebuttal, August 1996.

Market-based allocation of gas-supply costs of Fall River Gas Company.

143. **Md. PSC** 8725, Maryland electric-utilities merger; Maryland Office of People's Counsel. July 1996.

Proposed merger of Baltimore Gas & Electric Company, Potomac Electric Power Company, and Constellation Energy. Cost allocation of merger benefits and rate reductions.

144. **N.H. PUC** DR 96-150, Public Service Company of New Hampshire stranded costs; New Hampshire Office of Consumer Advocate. December 1996.

Market price of capacity and energy; value of generation plant; restructuring gain and stranded investment; legal status of PSNH acquisition premium; interim stranded-cost charges.

145. **Ont. Energy Board** EBRO 495, LRAM and shared-savings incentive for DSM performance of Consumers Gas; Green Energy Coalition. March 1997.

LRAM and shared-savings incentive mechanisms in rates for the Consumers Gas Company Ltd.

146. **New York PSC** 96-E-0897, Consolidated Edison restructuring plan; City of New York. April 1997.

Electric-utility competition and restructuring; critique of proposed settlement of Consolidated Edison Company; stranded costs; market power; rates; market access.

147. **Vt.** **PSB** 5980, proposed statewide energy plan; Vermont Department of Public Service. Direct, August 1997; rebuttal, December 1997.

Justification for and estimation of statewide avoided costs; guidelines for distributed IRP.

148. **Mass.** **DPU** 96-23, Boston Edison restructuring settlement; Utility Workers Union of America. September 1997.

Performance incentives proposed for the Boston Edison company.

149. **Vt.** **PSB** 5983, Green Mountain Power rate increase; Vermont Department of Public Service. Direct, October 1997; rebuttal, December 1997.

In three separate pieces of prefiled testimony, addressed the Green Mountain Power Corporation's (1) distributed-utility-planning efforts, (2) avoided costs, and (3) prudence of decisions relating to a power purchase from Hydro-Quebec.

150. **Mass.** **DPU** 97-63, Boston Edison proposed reorganization; Utility Workers Union of America. October 1997.

Increased costs and risks to ratepayers and shareholders from proposed reorganization; risks of diversification; diversion of capital from regulated to unregulated affiliates; reduction in Commission authority.

151. **Mass.** **DTE** 97-111, Commonwealth Energy proposed restructuring; Cape Cod Light Compact. Joint testimony with Jonathan Wallach, January 1998.

Critique of proposed restructuring plan filed to satisfy requirements of the electric-utility restructuring act of 1997. Failure of the plan to foster competition and promote the public interest.

152. **N.H.** **PUC** Docket DR 97-241, Connecticut Valley Electric fuel and purchased-power adjustments; City of Claremont, N.H. February 1998.

Prudence of continued power purchase from affiliate; market cost of power; prudence disallowances and cost-of-service ratemaking.

153. **Md.** **PSC** 8774, APS-DQE merger; Maryland Office of People's Counsel. February 1998.

Proposed power-supply arrangements between APS's potential operating subsidiaries; power-supply savings; market power.

154. **Vt.** **PSB** 6018, Central Vermont Public Service Co. rate increase; Vermont Department of Public Service. February 1998.

Prudence of decisions relating to a power purchase from Hydro-Quebec. Reasonableness of avoided-cost estimates. Quality of DU planning.

155. **Maine** PUC 97-580, Central Maine Power restructuring and rates; Maine Office of Public Advocate. May 1998; Surrebuttal, August 1998.

Determination of stranded costs; gains from sales of fossil, hydro, and biomass plant; treatment of deferred taxes; incentives for stranded-cost mitigation; rate design.

156. **Mass.** DTE 98-89, purchase of Boston Edison municipal street lighting; Towns of Lexington and Acton. Affidavit, August 1998.

Valuation of municipal streetlighting; depreciation; applicability of unbundled rate.

157. **Vt.** PSB 6107, Green Mountain Power rate increase; Vermont Department of Public Service. Direct, September 1998; Surrebuttal drafted but not filed, November 2000.

Prudence of decisions relating to a power purchase from Hydro-Quebec. Least-cost planning and prudence. Quality of DU planning.

158. **Mass.** DTE 97-120, Western Massachusetts Electric Company proposed restructuring; Massachusetts Attorney General. Joint testimony with Jonathan Wallach, October 1998. Joint surrebuttal with Jonathan Wallach, January 1999.

Market value of the three Millstone nuclear units under varying assumptions of plant performance and market prices. Independent forecast of wholesale market prices. Value of Pilgrim and TMI-1 asset sales.

159. **Md.** PSC 8794 and 8804, BG&E restructuring and rates; Maryland Office of People's Counsel. Direct, December 1998; rebuttal, March 1999.

Implementation of restructuring. Valuation of generation assets from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

160. **Md.** PSC 8795; Delmarva Power & Light restructuring and rates; Maryland Office of People's Counsel. December 1998.

Implementation of restructuring. Valuation of generation assets and purchases from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

161. **Md.** PSC 8797, Potomac Edison Company restructuring and rates; Maryland Office of People's Counsel. Direct, January 1999; rebuttal, March 1999.

Implementation of restructuring. Valuation of generation assets and purchases from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

162. **Conn.** DPUC 99-02-05, Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

Projections of market price. Valuation of purchase agreements and nuclear and non-nuclear assets from comparable-sales and cash-flow analyses.

163. Conn. DPUC 99-03-04, United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

Projections of market price. Valuation of purchase agreements and nuclear assets from comparable-sales and cash-flow analyses.

164. Wash. UTC UE-981627, PacifiCorp–Scottish Power merger, Office of the Attorney General. June 1999.

Review of proposed performance standards and valuation of performance. Review of proposed low-income assistance.

165. Utah PSC 98-2035-04, PacifiCorp–Scottish Power merger, Utah Committee of Consumer Services. June 1999.

Review of proposed performance standards and valuation of performance.

166. Conn. DPUC 99-03-35, United Illuminating Company proposed standard offer; Connecticut Office of Consumer Counsel. July 1999.

Design of standard offer by rate class. Design of price adjustments to preserve rate decrease. Market valuations of nuclear plants. Short-term stranded cost

167. Conn. DPUC 99-03-36, Connecticut Light and Power Company proposed standard offer; Connecticut Office of Consumer Counsel. Direct, July 1999; supplemental, July 1999.

Design of standard offer by rate class. Design of price adjustments to preserve rate decrease. Market valuations of nuclear plants. Short-term stranded cost.

168. W. Va. PSC 98-0452-E-GI, electric-industry restructuring, West Virginia Consumer Advocate. July 1999.

Market value of generating assets of, and restructuring gain for, Potomac Edison, Monongahela Power, and Appalachian Power. Comparable-sales and cash-flow analyses.

169. Ont. Energy Board RP-1999-0034, Ontario performance-based rates; Green Energy Coalition. September 1999.

Rate design. Recovery of demand-side-management costs under PBR. Incremental costs.

170. Conn. DPUC 99-08-01, standards for utility restructuring; Connecticut Office of Consumer Counsel. Direct, November 1999; supplemental, January 2000.

Appropriate role of regulation. T&D reliability and service quality. Performance standards and customer guarantees. Assessing generation adequacy in a competitive market.

171. **Conn. Superior Court** CV 99-049-7239, Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. Affidavit, December 1999.

Errors of the Conn. DPUC in deriving discounted-cash-flow valuations for Millstone and Seabrook, and in setting minimum bid price.

172. **Conn. Superior Court** CV 99-049-7597, United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. December 1999.

Errors of the Conn. DPUC, in its discounted-cash-flow computations, in selecting performance assumptions for Seabrook, and in setting minimum bid price.

173. **Ont. Energy Board** RP-1999-0044, Ontario Hydro transmission-cost allocation and rate design; Green Energy Coalition. January 2000.

Cost allocation and rate design. Net vs. gross load billing. Export and wheeling-through transactions. Environmental implications of utility proposals.

174. **Utah PSC** 99-2035-03, PacifiCorp Sale of Centralia plant, mine, and related facilities; Utah Committee of Consumer Services. January 2000.

Prudence of sale and management of auction. Benefits to ratepayers. Allocation and rate treatment of gain.

175. **Conn. DPUC** 99-09-12, Nuclear Divestiture by Connecticut Light & Power and United Illuminating; Connecticut Office of Consumer Counsel. January 2000.

Market for nuclear assets. Optimal structure of auctions. Value of minority rights. Timing of divestiture.

176. **Ont. Energy Board** RP-1999-0017, Union Gas PBR proposal; Green Energy Coalition. March 2000.

Lost-revenue-adjustment and shared-savings incentive mechanisms for Union Gas DSM programs. Standards for review of targets and achievements, computation of lost revenues. Need for DSM expenditure true-up mechanism.

177. **N.Y. PSC** 99-S-1621, Consolidated Edison steam rates; City of New York. April 2000.

Allocation of costs of former cogeneration plants, and of net proceeds of asset sale. Economic justification for steam-supply plans. Depreciation rates. Weather normalization and other rate adjustments.

178. **Maine PUC** 99-666, Central Maine Power alternative rate plan; Maine Public Advocate. Direct, May 2000; Surrebuttal, August 2000.

Likely merger savings. Savings and rate reductions from recent mergers. Implications for rates.

179. **Mass.** EFSB 97-4, Massachusetts Municipal Wholesale Electric Company gas-pipeline proposal; Town of Wilbraham, Mass. June 2000.

Economic justification for natural-gas pipeline. Role and jurisdiction of EFSB.

180. **Conn.** DPUC 99-09-03; Connecticut Natural Gas Corporation merger and rate plan; Connecticut office of Consumer Counsel. September 2000.

Performance-based ratemaking in light of mergers. Allocation of savings from merger. Earnings-sharing mechanism.

181. **Conn.** DPUC 99-09-12RE01, Proposed Millstone sale; Connecticut Office of Consumer Counsel. November 2000.

Requirements for review of auction of generation assets. Allocation of proceeds between units.

182. **Mass.** DTE 01-25, Purchase of streetlights from Commonwealth Electric; Cape Light Compact. January 2001

Municipal purchase of streetlights; Calculation of purchase price under state law; Determination of accumulated depreciation by asset.

183. **Conn.** DPUC 00-12-01 and 99-09-12RE03, Connecticut Light & Power rate design and standard offer; Connecticut Office of Consumer Counsel. March 2001.

Rate design and standard offer under restructuring law; Future rate impacts; Transition to restructured regime; Comparison of Connecticut and California restructuring challenges.

184. **Vt.** PSB 6460 & 6120, Central Vermont Public Service rates; Vermont Department of Public Service. Direct, March 2001; Surrebuttal, April 2001.

Review of decision in early 1990s to commit to long-term uneconomic purchase from Hydro Québec. Calculation of present damages from imprudence.

185. **N.J.** BPU EM00020106, Atlantic City Electric Company sale of fossil plants; New Jersey Ratepayer Advocate. Affidavit, May 2001.

Comparison of power-supply contracts. Comparison of plant costs to replacement power cost. Allocation of sales proceeds between subsidiaries.

186. **N.J.** BPU GM00080564, Public Service Electric and Gas transfer of gas supply contracts; New Jersey Ratepayer Advocate. Direct, May 2001.

Transfer of gas transportation contracts to unregulated affiliate. Potential for market power in wholesale gas supply and electric generation. Importance of reliable gas supply. Valuation of contracts. Effect of proposed requirements contract on rates. Regulation and design of standard-offer service.

187. **Conn.** **DPUC** 99-04-18 Phase 3, 99-09-03 Phase 2; Southern Connecticut Natural Gas and Connecticut Natural Gas rates and charges; Connecticut Office of Consumer Counsel. Direct, June 2001; supplemental, July 2001.

Identifying, quantifying, and allocating merger-related gas-supply savings between ratepayers and shareholders. Establishing baselines. Allocations between affiliates. Unaccounted-for gas.

188. **N.J. BPU** EX01050303, New Jersey electric companies' procurement of basic supply; New Jersey Ratepayer Advocate. August 2001.

Review of proposed statewide auction for purchase of power requirements. Market power. Risks to ratepayers of proposed auction.

189. **N.Y.** **PSC** 00-E-1208, Consolidated Edison rates; City of New York. October 2001.

Geographic allocation of stranded costs. Locational and postage-stamp rates. Causation of stranded costs. Relationship between market prices for power and stranded costs.

190. **Mass.** **DTE** 01-56, Berkshire Gas Company; Massachusetts Attorney General. October 2001.

Allocation of gas costs by load shape and season. Competition and cost allocation.

191. **N.J.** **BPU** EM00020106, Atlantic City Electric proposed sale of fossil plants; New Jersey Ratepayer Advocate. December 2001.

Current market value of generating plants vs. proposed purchase price.

192. **Vt.** **PSB** 6545, Vermont Yankee proposed sale; Vermont Department of Public Service. January 2002.

Comparison of sales price to other nuclear sales. Evaluation of auction design and implementation. Review of auction manager's valuation of bids.

193. **Conn. Siting Council** 217, Connecticut Light & Power proposed transmission line from Plumtree to Norwalk; Connecticut Office of Consumer Counsel. March 2002.

Nature of transmission problems. Potential for conservation and distributed resources to defer, reduce or avoid transmission investment. CL&P transmission planning process. Joint testimony with John Plunkett.

194. **Vt.** **PSB** 6596, Citizens Utilities rates; Vermont Department of Public Service. Direct, March 2002; rebuttal, May 2002.

Review of 1991 decision to commit to long-term uneconomic purchase from Hydro Québec. Alternatives; role of transmission constraints. Calculation of present damages from imprudence.

195. **Conn.** DPUC 01-10-10, United Illuminating rate plan; Connecticut Office of Consumer Counsel. April 2002

Allocation of excess earnings between shareholders and ratepayers. Asymmetry in treatment of over- and under-earning. Accelerated amortization of stranded costs. Effects of power-supply developments on ratepayer risks. Effect of proposed rate plan on utility risks and required return.

196. **Conn.** DPUC 01-12-13RE01, Seabrook proposed sale; Connecticut Office of Consumer Counsel. July 2002

Comparison of sales price to other nuclear sales. Evaluation of auction design and implementation. Assessment of valuation of purchased-power contracts.

197. **Ont. Energy Board** RP-2002-0120, review of transmission-system code; Green Energy Coalition. October 2002.

Cost allocation. Transmission charges. Societal cost-effectiveness. Environmental externalities.

198. **N.J.** BPU ER02080507, Jersey Central Power & Light rates; N.J. Division of the Ratepayer Advocate. Phase I December 2002; Phase II (oral) July 2003.

Prudence of procurement of electrical supply. Documentation of procurement decisions. Comparison of costs for subsidiaries with fixed versus flow-through cost recovery.

199. **Conn.** DPUC 03-07-02, CL&P rates; AARP. October 2003

Proposed distribution investments, including prudence of prior management of distribution system and utility's failure to make investments previously funded in rates. Cost controls. Application of rate cap. Legislative intent.

200. **Conn.** DPUC 03-07-01, CL&P transitional standard offer; AARP. November 2003.

Application of rate cap. Legislative intent.

201. **Vt.** PSB 6596, Vermont Electric Power Company and Green Mountain Power Northwest Reliability transmission plan; Conservation Law Foundation. December 2003.

Inadequacies of proposed transmission plan. Failure of to perform least-cost planning. Distributed resources.

202. **Ohio** PUC 03-2144-EL-ATA, Ohio Edison, Cleveland Electric, and Toledo Edison Cos. rates and transition charges; Green Mountain Energy Co. February 2004.

Pricing of standard-offer service in competitive markets. Critique of anticompetitive features of proposed standard-offer supply, including non-bypassable charges.

203. **N.Y. PSC** 03-G-1671 & 03-S-1672, Consolidated Edison company steam and gas rates; City of New York. Direct March 2004; rebuttal April 2004; settlement June 2004.

Prudence and cost allocation for the East River Repowering Project. Gas and steam energy conservation. Opportunities for cogeneration at existing steam plants.

204. **N.Y. PSC** 04-E-0572, Consolidated Edison rates and performance; City of New York. Direct, September 2004; rebuttal, October 2004.

Consolidated Edison's role in promoting adequate supply and demand resources. Integrated resource and T&D planning. Performance-based ratemaking and streetlighting.

205. **Ont. Energy Board** RP 2004-0188, cost recovery and DSM for Ontario electric-distribution utilities; Green Energy Coalition. Exhibit, December 2004.

Differences in ratemaking requirements for customer-side conservation and demand management versus utility-side efficiency improvements. Recovery of lost revenues or incentives. Reconciliation mechanism.

206. **Mass. DTE** 04-65, Cambridge Electric Light Co. streetlighting; City of Cambridge. Direct, October 2004; supplemental, January 2005.

Calculation of purchase price of street lights by the City of Cambridge.

207. **N.Y. PSC** 04-W-1221, rates, rules, charges, and regulations of United Water New Rochelle; Town of Eastchester and City of New Rochelle. Direct, February 2005.

Size and financing of proposed interconnection. Rate design. Water-mains replacement and related cost recovery. Lost and unaccounted-for water.

208. **N.Y. PSC** 05-M-0090, system-benefits charge; City of New York. Comments, March 2005.

Assessment and scope of, and potential for, New York system-benefits charges.

209. **Md. PSC** 9036, Baltimore Gas & Electric rates; Maryland Office of People's Counsel. Direct, August 2005.

Allocation of costs. Design of rates. Interruptible and firm rates.

210. **B.C. UC** 3698388, British Columbia Hydro resource-acquisition plan; British Columbia Sustainable Energy Association and Sierra Club of Canada BC Chapter. September 2005.

Renewable energy and DSM. Economic tests of cost-effectiveness. Costs avoided by DSM.

211. **Conn. DPUC** 05-07-18, financial effect of long-term power contracts; Connecticut Office of Consumer Counsel. September 2005.

Assessment of effect of DSM, distributed generation, and capacity purchases on financial condition of utilities.

212. **Conn. DPUC** 03-07-01RE03 & 03-07-15RE02, incentives for power procurement; Connecticut Office of Consumer Counsel. Direct, September 2005; Additional, April 2006.

Utility obligations for generation procurement. Application of standards for utility incentives. Identification and quantification of effects of timing, load characteristics, and product definition.

213. **Conn. DPUC** Docket 05-10-03, Connecticut L&P; time-of-use, interruptible, and seasonal rates; Connecticut Office of Consumer Counsel. Direct and Supplemental Testimony February 2006.

Seasonal and time-of-use differentiation of generation, congestion, transmission and distribution costs; fixed and variable peak-period timing; identification of pricing seasons and seasonal peak periods; cost-effectiveness of time-of-use rates.

214. **Ont. Energy Board** Case EB-2005-0520, Union Gas rates; School Energy Coalition. Evidence, April 2006.

Rate design related to splitting commercial rate class into two classes. New break point, cost allocation, customer charges, commodity rate blocks.

215. **Ont. Energy Board** EB-2006-0021, Natural-gas demand-side-management generic issues proceeding; School Energy Coalition. Evidence, June 2006.

Multi-year planning and budgeting; lost-revenue adjustment mechanism; determining savings for incentives; oversight; program screening.

216. **Ind. URC** 42943 and 43046, Vectren Energy DSM proceedings; Citizens Action Coalition. Direct, June 2006.

Rate decoupling and energy-efficiency goals.

217. **Penn. PUC** 00061346, Duquesne Lighting; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

Real-time and time-dependent pricing; benefits of time-dependent pricing; appropriate metering technology; real-time rate design and customer information

218. **Penn. PUC** R-00061366 et al., rate-transition-plan proceedings of Metropolitan Edison and Pennsylvania Electric; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

Real-time and time-dependent pricing; appropriate metering technology; real-time rate design and customer information.

219. **Conn.** **DPUC** 06-01-08, Connecticut L&P procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings quarterly since September 2006 to October 2013.

Conduct of auction; review of bids; comparison to market prices; selection of winning bidders.

220. **Conn.** **DPUC** 06-01-08, United Illuminating procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings quarterly August 2006 to October 2013.

Conduct of auction; review of bids; comparison to market prices; selection of winning bidders.

221. **N.Y.** **PSC** Case No. 06-M-1017, policies, practices, and procedures for utility commodity supply service; City of New York. Comments, November and December 2006.

Multi-year contracts, long-term planning, new resources, procurement by utilities and other entities, cost recovery.

222. **Conn.** **DPUC** 06-01-08, procurement of power for standard service and last-resort service, lessons learned; Connecticut Office Of Consumer Counsel. Comments and Technical Conferences December 2006 and January 2007.

Sharing of data and sources; benchmark prices; need for predictability, transparency and adequate review; utility-owned resources; long-term firm contracts.

223. **Ohio** **PUC** PUCO 05-1444-GA-UNC, recovery of conservation costs, decoupling, and rate-adjustment mechanisms for Vectren Energy Delivery of Ohio; Ohio Consumers' Counsel. February 2007.

Assessing cost-effectiveness of natural-gas energy-efficiency programs. Calculation of avoided costs. Impact on rates. System benefits of DSM.

224. **N.Y.** **PSC** 06-G-1332, Consolidated Edison Rates and Regulations; City of New York. March 2007.

Gas energy efficiency: benefits to customers, scope of cost-effective programs, revenue decoupling, shareholder incentives.

225. **Alb.** **EUB** 1500878, ATCo Electric rates; Association of Municipal Districts & Counties and Alberta Federation of Rural Electrical Associations. May 2007.

Direct assignment of distribution costs to street lighting. Cost causation and cost allocation. Minimum-system and zero-intercept classification.

226. **Conn.** DPUC 07-04-24, review of capacity contracts under Energy Independence Act; Connecticut Office of Consumer Counsel. Direct (with Jonathan Wallach), June 2007.

Assessment of proposed capacity contracts for new combined-cycle, peakers and DSM. Evaluation of contracts for differences, modeling of energy, capacity and forward-reserve markets. Corrections of errors in computation of costs, valuation of energy-price effects of peakers, market-driven expansion plans and retirements, market response to contracted resource additions, DSM proposal evaluation.

227. **N.Y.** PSC 07-E-0524, Consolidated Edison electric rates; City of New York. September 2007.

Energy-efficiency planning. Recovery of DSM costs. Decoupling of rates from sales. Company incentives for DSM. Advanced metering. Resource planning.

228. **Man.** PUB 136-07, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. February 2008.

Revenue allocation, rate design, and demand-side management. Estimation of marginal costs and export revenues.

229. **Mass.** EFSB 07-7, DPU 07-58 & -59; proposed Brockton Power Company plant; Alliance Against Power Plant Location. March 2008

Regional supply and demand conditions. Effects of plant construction and operation on regional power supply and emissions.

230. **Conn.** DPUC 08-01-01, peaking generation projects; Connecticut Office of Consumer Counsel. Direct (with Jonathan Wallach), April 2008.

Assessment of proposed peaking projects. Valuation of peaking capacity. Modeling of energy margin, forward reserves, other project benefits.

231. **Ont. Energy Board** 2007-0905, Ontario Power Generation payments; Green Energy Coalition. April 2008.

Cost of capital for Hydro and nuclear investments. Financial risks of nuclear power.

232. **Utah** PSC 07-035-93, Rocky Mountain Power Rates; Utah Committee of Consumer Services. July 2008

Cost allocation and rate design. Cost of service. Correct classification of generation, transmission, and purchases.

233. **Ont. Energy Board** 2007-0707, Ontario Power Authority integrated system plan; Green Energy Coalition, Penimba Institute, and Ontario Sustainable Energy Association. Evidence (with Jonathan Wallach and Richard Mazzini), August 2008.

Critique of integrated system plan. Resource cost and characteristics; finance cost. Development of least-cost green-energy portfolio.

234. **N.Y. PSC** 08-E-0596, Consolidated Edison electric rates; City of New York. September 2008.

Estimated bills, automated meter reading, and advanced metering. Aggregation of building data. Targeted DSM program design. Using distributed generation to defer T&D investments.

235. **Conn. DPUC** 08-07-01, Integrated resource plan; Connecticut Office of Consumer Counsel. September 2008.

Integrated resource planning scope and purpose. Review of modeling and assumptions. Review of energy efficiency, peakers, demand response, nuclear, and renewables. Structuring of procurement contracts.

236. **Man. PUB** 2008 MH EIIR, Manitoba Hydro intensive industrial rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. November 2008.

Marginal costs. Rate design. Time-of-use rates.

237. **Md. PSC** 9036, Columbia Gas rates; Maryland Office of People's Counsel. January 2009.

Cost allocation and rate design. Critique of cost-of-service studies.

238. **Vt. PSB** 7440, extension of authority to operate Vermont Yankee; Conservation Law Foundation and Vermont Public Interest Research Group. Direct, February 2009; Surrebuttal, May 2009.

Adequacy of decommissioning funding. Potential benefits to Vermont of revenue-sharing provision. Risks to Vermont of underfunding decommissioning fund.

239. **N.S. UARB** M01439, Nova Scotia Power DSM and cost recovery; Nova Scotia Consumer Advocate. May 2009.

Recovery of demand-side-management costs and lost revenue.

240. **N.S. UARB** M01496, proposed biomass project; Nova Scotia Consumer Advocate. June 2009.

Procedural, planning, and risk issues with proposed power-purchase contract. Biomass price index. Nova Scotia Power's management of other renewable contracts.

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242. **Mass.** DPU 09-39, NGrid rates; Mass. Department of Energy Resources. August 2009.

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243. **Utah** PSC 09-035-23, Rocky Mountain Power rates; Utah Office of Consumer Services. Direct, October 2009; rebuttal, November 2009.

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244. **Utah** PSC 09-035-15, Rocky Mountain Power energy-cost-adjustment mechanism; Utah Office of Consumer Services. Direct, November 2009; surrebuttal, January 2010.

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245. **Penn.** PUC R-2009-2139884, Philadelphia Gas Works energy efficiency and cost recovery; Philadelphia Gas Works. December 2009.

Avoided gas costs. Recovery of efficiency-program costs and lost revenues. Rate impacts of DSM.

246. **B.C.** UC 3698573, British Columbia Hydro rates; British Columbia Sustainable Energy Association and Sierra Club British Columbia. February 2010.

Rate design and energy efficiency.

247. **Ark.** PSC 09-084-U, Entergy Arkansas rates; National Audubon Society and Audubon Arkansas. Direct, February 2010; surrebuttal, April 2010.

Recovery of revenues lost to efficiency programs. Determination of lost revenues. Incentive and recovery mechanisms.

248. **Ark.** PSC 10-010-U, Energy efficiency; National Audubon Society and Audubon Arkansas. Direct, March 2010; reply, April 2010.

Regulatory framework for utility energy-efficiency programs. Fuel-switching programs. Program administration, oversight, and coordination. Rationale for commercial and industrial efficiency programs. Benefit of energy efficiency.

249. **Ark.** PSC 08-137-U, Generic rate-making; National Audubon Society and Audubon Arkansas. Direct, March 2010; supplemental, October 2010; reply, October 2010.

Calculation of avoided costs. Recovery of utility energy-efficiency-program costs and lost revenues. Shareholder incentives for efficiency-program performance.

250. **Plymouth, Mass., Superior Court** Civil Action No. PLCV2006-00651-B (Hingham Municipal Lighting Plant v. Gas Recovery Systems LLC et al.), Breach of agreement; defendants. Affidavit, May 2010.

Contract interpretation. Meaning of capacity measures. Standard practices in capacity agreements. Power-pool rules and practices. Power planning and procurement.

251. **N.S. UARB** M02961, Port Hawkesbury biomass project; Nova Scotia Consumer Advocate. June 2010.

Least-cost planning and renewable-energy requirements. Feasibility versus alternatives. Unknown or poorly estimated costs.

252. **Mass. DPU** 10-54, NGrid purchase of long-term power from Cape Wind; Natural Resources Defense Council et al. July 2010.

Effects of renewable-energy projects on gas and electric market prices. Impacts on system reliability and peak loads. Importance of PPAs to renewable development. Effectiveness of proposed contracts as price edges.

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Allocation of gas- and electric-distribution costs. Critique of minimum-system analyses and direct assignment of shared plant. Allocation of environmental compliance costs. Allocation of revenue increases among rate classes.

254. **Ont. Energy Board** 2010-0008, Ontario Power Generation facilities charges; Green Energy Coalition. Evidence, August 2010.

Critique of including a return on CWIP in current rates. Setting cost of capital by business segment.

255. **N.S. UARB** Matter No. 03454, Heritage Gas rates; Nova Scotia Consumer Advocate. October 2010.

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256. **Man. PUB** 17/10, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. December 2010.

Revenue-allocation and rate design. DSM program.

257. **N.S. UARB** M03665, Nova Scotia Power depreciation rates; Nova Scotia Consumer Advocate. February 2011.

Depreciation and rates.

258. **New Orleans City Council** UD-08-02, Entergy IRP rules; Alliance for Affordable Energy. December 2010.

Integrated resource planning: Purpose, screening, cost recovery, and generation planning.

259. **N.S. UARB** M03665, depreciation Rates of Nova Scotia Power; Nova Scotia Consumer Advocate. February 2011.

Steam-plant retirement dates, post-retirement use, timing of decommissioning and removal costs.

260. **N.S. UARB M**03632, renewable-energy community-based feed-in tariffs; Nova Scotia Consumer Advocate. March 2011.

Adjustments to estimate of cost-based feed-in tariffs. Rate effects of feed-in tariffs.

261. **Mass. EFSB** 10-2/**DPU** 10-131, 10-132; NStar transmission; Town of Sandwich, Mass. Direct, May 2011; Surrebuttal, June 2011.

Need for new transmission; errors in load forecasting; probability of power outages.

262. **Utah PSC** 10-035-124, Rocky Mountain Power rate case; Utah Office of Consumer Services. June 2011.

Load data, allocation of generation plants, scrubbers, power purchases, and service drops. Marginal cost study: inclusion of all load-related transmission projects, critique of minimum- and zero-intercept methods for distribution. Residential rate design.

263. **N.S. UARB** M04104; Nova Scotia Power general rate application; Nova Scotia Consumer Advocate. August 2011.

Cost allocation: allocation of costs of wind power and substations. Rate design: marginal-cost-based rates, demand charges, time-of-use rates.

264. **N.S. UARB** M04175, Load-retention tariff; Nova Scotia Consumer Advocate. August 2011.

Marginal cost of serving very large industrial electric loads; risk, incentives and rate design.

265. **Ark. PSC** 10-101-R, Rulemaking re self-directed energy efficiency for large customers; National Audubon Society and Audubon Arkansas. July 2011.

Structuring energy-efficiency programs for large customers.

266. **Okla.** CC PUD 201100077, current and pending federal regulations and legislation affecting Oklahoma utilities; Sierra Club. Comments July, October 2011; presentation July 2011.

Challenges facing Oklahoma coal plants; efficiency, renewable and conventional resources available to replace existing coal plants; integrated environmental compliance planning.

267. **Nevada PUC** 11-08019, integrated analysis of resource acquisition, Sierra Club. Comments, September 2011; hearing, October 2011.

Scoping of integrated review of cost-effectiveness of continued operation of Reid Gardner 1–3 coal units.

268. **La. PSC** R-30021, Louisiana integrated-resource-planning rules; Alliance for Affordable Energy. Comments, October 2011.

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269. **Okla.** CC PUD 201100087, Oklahoma Gas and Electric Company electric rates; Sierra Club. November 2011.

Resource monitoring and acquisition. Benefits to ratepayers of energy conservation and renewables. Supply planning

270. **Ky. PSC** 2011-00375, Kentucky utilities' purchase and construction of power plants; Sierra Club and National Resources Defense Council. December 2011.

Assessment of resources, especially renewables. Treatment of risk. Treatment of future environmental costs.

271. **N.S. UARB** M04819, demand-side-management plan of Efficiency Nova Scotia; Nova Scotia Consumer Advocate. May 2012.

Avoided costs. Allocation of costs. Reporting of bill effects.

272. **Kansas CC** 12-GIMX-337-GIV, utility energy-efficiency programs; The Climate and Energy Project. June 2012.

Cost-benefit tests for energy-efficiency programs. Collaborative program design.

273. **N.S. UARB** M04862, Port Hawksbury load-retention mechanism; Nova Scotia Consumer Advocate. June 2012.

Effect on ratepayers of proposed load-retention tariff. Incremental capital costs, renewable-energy costs, and costs of operating biomass cogeneration plant.

274. **Utah PSC** 11-035-200, Rocky Mountain Power Rates; Utah Office of Consumer Council. June 2012.

Cost allocation. Estimation of marginal customer costs.

275. **Ark. PSC** 12-008-U, environmental controls at Southwestern Electric Power Company's Flint Creek plant; Sierra Club. Direct, June 2012; rebuttal, August 2012; further, March 2013.

Costs and benefits of environmental retrofit to permit continued operation of coal plant, versus other options including purchased gas generation, efficiency, and wind. Fuel-price projections. Need for transmission upgrades.

276. **U.S. EPA** EPA-R09-OAR-2012-0021, air-quality implementation plan; Sierra Club. September 2012.

Costs, financing, and rate effects of Apache coal-plant scrubbers. Relative incomes in service territories of Arizona Coop and other utilities.

277. **Arkansas PSC** Docket No. 07-016-U; Entergy Arkansas' integrated resource plan; Audubon Arkansas. Comments, September 2012.

Estimation of future gas prices. Estimation of energy-efficiency potential. Screening of resource decisions. Wind costs.

278. **Vt. PSB** 7862, Entergy Nuclear Vermont and Entergy Nuclear Operations petition to operate Vermont Yankee; Conservation Law Foundation. October 2012.

Effect of continued operation on market prices. Value of revenue-sharing agreement. Risks of underfunding decommissioning fund.

279. **Man. PUB** 2012–13 GRA, Manitoba Hydro rates; Green Action Centre. November 2012.

Estimation of marginal costs. Fuel switching.

280. **N.S. UARB** M05339, Capital Plan of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2013.

Economic and financial modeling of investment. Treatment of AFUDC.

281. **N.S. UARB** M05416, South Canoe wind project of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2013.

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282. **N.S. UARB** 05419; Maritime Link transmission project and related contracts, Nova Scotia Consumer Advocate and Small Business Advocate. Direct, April 2013; supplemental (with Seth Parker), November 2013.

Load forecast, including treatment of economy energy sales. Wind power cost forecasts. Cost effectiveness and risk of proposed project. Opportunities for improving economics of project.

283. **Ont. Energy Board** 2012-0451/0433/0074, Enbridge Gas Greater Toronto Area project; Green Energy Coalition. June 2013, revised August 2013.

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284. **N.S. UARB** 05092, tidal-energy feed-in-tariff rate; Nova Scotia Consumer Advocate. August 2013.

Purchase rate for test and demonstration projects. Maximizing benefits under rate-impact caps. Pricing to maximize provincial advantage as a hub for emerging tidal-power industry.

285. **N.S. UARB** 05473, Nova Scotia Power 2013 cost-of-service study; Nova Scotia Consumer Advocate. October 2013.

Cost-allocation and rate design.

286. **B.C. UC** 3698715 & 3698719; performance-based ratemaking plan for FortisBC companies; British Columbia Sustainable Energy Association and Sierra Club British Columbia. Direct (with John Plunkett), December 2013.

Rationale for enhanced gas and electric DSM portfolios. Correction of utility estimates of electric avoided costs. Errors in program screening. Program potential. Recommended program ramp-up rates.

287. **Conn. PURA** Docket No. 14-01-01, Connecticut Light and Power Procurement of Standard Service and Last-Resort Service. July and October 2014.

Proxy for review of bids. Oversight of procurement and selection process.

288. **Conn. PURA** Docket No. 14-01-02, United Illuminating Procurement of Standard Service and Last-Resort Service. January, April, July, and October 2014.

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289. **Man. PUB** 2014, need for and alternatives to proposed hydro-electric facilities; Green Action Centre. Evidence (with Wesley Stevens) February 2014.

Potential for fuel switching, DSM, and wind to meet future demand.

290. **Utah PSC** 13-035-184, Rocky Mountain Power Rates; Utah Office of Consumer Services. May 2014.

Class cost allocation. Classification and allocation of generation plant and purchased power. Principles of cost-causation. Design of backup rates.

291. **Minn. PSC** E002/GR-13-868, Northern States Power rates; Clean Energy Intervenors. Direct, June 2014; rebuttal, July 2014; surrebuttal, August 2014.

Inclining-block residential rate design. Rationale for minimizing customer charges.

292. **Cal.** PUC Rulemaking 12-06-013, electric rates and rate structures; Natural Resources Defense Council. September 2014.

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293. **Md.** PSC 9361, proposed merger of PEPCo Holdings into Exelon; Sierra Club and Chesapeake Climate Action Network. Direct, December 2014; surrebuttal, January 2015.

Effect of proposed merger on Consumer bills, renewable energy, energy efficiency, and climate goals.

294. **N.S.** UARB M06514, 2015 capital-expenditure plan of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2015.

Economic evaluation of proposed projects. Treatment of AFUDC, overheads, and replacement costs of lost generation. Computation of rate effects of spending plan.

295. **Md.** PSC 9153 et al., Maryland energy-efficiency programs; Maryland Office of People's Counsel. January 2015.

Costs avoided by demand-side management. Demand-reduction-induced price effects.

296. **Québec** Régie de L'énergie R-3876-2013 phase 1, Gaz Métro cost allocation and rate structure; Regroupement des organismes environnementaux en énergie and Union des consommateurs. February 2015

Classification of the area-spanning system; minimum system and more realistic approaches. Allocation of overhead, energy-efficiency, gas-supply, engineering-and-planning, and billing costs.

297. **Conn. PURA** Docket No. 15-01-01, Connecticut Light and Power Procurement of Standard Service and Last-Resort Service. February and July 2015.

Proxy for review of bids. Oversight of procurement and selection process.

298. **Conn. PURA** Docket No. 15-01-02, United Illuminating Procurement of Standard Service and Last-Resort Service. February, July, and October 2015.

Proxy for review of bids. Oversight of procurement and selection process.

299. **Ky.** PSC 2014-00371, Kentucky Utilities electric rates; Sierra Club. March 2015.

Review basis for higher customer charges, including cost allocation. Design of time-of-day rates.

300. **Ky.** **PSC** 2014-00372, Louisville Gas and Electric electric rates; Sierra Club. March 2015.

Review basis for higher customer charges, including cost allocation. Design of time-of-day rates.

301. **Mich.** **PSC** U-17767, DTE Electric Company rates; Michigan Environmental Council, Sierra Club, and Natural Resource Defense Council. May 2015.

Cost effectiveness of pollution-control retrofits versus retirements. Market prices. Costs of alternatives.

302. **N.S.** **UARB** M06733, supply agreement between Efficiency One and Nova Scotia Power; Nova Scotia Consumer Advocate. June 2015.

Avoided costs. Cost-effectiveness screening of DSM. Portfolio design. Affordability and bill effects.

303. **Penn.** **PUC** P-2014-2459362, Philadelphia Gas Works DSM, universal-service, and energy-conservation plans; Philadelphia Gas Works. Direct, May 2015; Rebuttal, July 2015.

Avoided costs. Recovery of lost margin.

304. **Ont. Energy Board** EB-2015-0029/0049, 2015–2020 DSM Plans Of Enbridge Gas Distribution and Union Gas, Green Energy Coalition. Evidence July 31, 2015, Corrected August 12, 2015.

Avoided costs: price mitigation, carbon prices, marginal gas supply costs, avoidable distribution costs, avoidable upstream costs (including utility-owned pipeline facilities).

305. **PUC Ohio** Case No. 14-1693-EL-RDR, AEP Ohio Affiliate purchased-power agreement, Sierra Club. September 2015.

Economics of proposed PPA, market energy and capacity projections. Risk shifting. Lack of price stability and reliability benefits. Market viability of PPA units.

306. **N.S.** **UARB** Matter No. M06214, NS Power Renewable-to-Retail rate, Nova Scotia Consumer Advocate. November 2015.

Review of proposed design of rate for third-party sales of renewable energy to retail customers. Distribution, transmission and generation charges.

307. **PUC Texas** Docket No. 44941, El Paso Electric rates; Energy Freedom Coalition of America. December 2015.

Cost allocation and rate design. Effect of proposed DG rate on solar customers. Load shapes of residential customers with and without solar. Problems with demand charges.

308. **N.S. UARB** Matter No. M07176, NS Power 2016 Capital Expenditures Plan, Nova Scotia Consumer Advocate. February 2016.

Economic evaluation of proposed projects, including replacement energy costs and modeling of equipment failures. Treatment of capitalized overheads and depreciation cash flow in computation of rate effects of spending plan.

309. **Md. PSC** Case No. 9406, BGE Application for recovery of Smart Meter costs, Maryland Office of People's Counsel. Direct February 2016, Rebuttal March 2016, Surrebuttal March 2016.

Assessment of benefits of Smart Meter programs for energy revenue, load reductions and price mitigation; capacity load reductions and price mitigation; free riders and load shifting in peak-time rebate (PTR) program; cost of PTR participation; effect of load reductions on PJM capacity obligations, capacity prices and T&D costs.

310. **City of Austin TX**, Austin Energy 2016 Rate Review, Sierra Club and Public Citizen. May 2016

Allocation of generation costs. Residential rate design. Geographical rate differentials. Recognition of coal-plant retirement costs.

311. **Manitoba PUB**, Manitoba Hydro Cost of Service Methodology Review, Green Action Centre. June 2016, reply August 2016.

Allocation of generation costs. Identifying generation-related transmission assets. Treatment of subtransmission. Classification of distribution lines. Allocation of distribution substations and lines. Customer allocators. Shared service drops.

312. **Md. PSC** Case No. 9418, PEPCo Application for recovery of Smart Meter costs, Maryland Office of People's Counsel. Direct July 2016, Rebuttal August 2016, Surrebuttal September 2016.

Assessment of benefits of Smart Meter programs for energy revenue, load reductions and price mitigation; load reductions in dynamic-pricing (DP) program; cost of DP participation; effect of load reductions on PJM capacity obligations, capacity prices and T&D costs.

313. **Md. PSC** Case No. 9424, Delmarva P&L Application for recovery of Smart Meter costs, Maryland Office of People's Counsel. Direct September 2016, Rebuttal October 2016, Surrebuttal October 2016.

Estimation of effects of Smart Meter programs—dynamic pricing (DP), conservation voltage reduction and an informational program—on wholesale revenues, wholesale prices and avoided costs; estimating load reductions from the DP program; cost of DP participation; effect of load reductions on PJM capacity obligations, capacity prices and T&D costs.

314. **N.H. PUC** Docket No. DE 16-576, Alternative Net Metering Tariffs, Conservation Law Foundation. Direct October 2016, Reply December 2016.

Framework for evaluating rates for distributed generation. Costs avoided and imposed by distributed solar. Rate design for distributed generation.

315. **Puerto Rico Energy Commission** CEPR-AP-2015-0001, Puerto Rico Electric Power Authority rate proceeding, PR Energy Commission. Report December 2016.

Comprehensive review of structure of electric utility, cost causation, load data, cost allocation, revenue allocation, marginal costs, retail rate designs, identification and treatment of customer subsidies, structuring rate riders, and rates for distributed generation and net metering.

316. **N.S. UARB** Matter No. M07745, NS Power 2017 Capital Expenditures Plan, Nova Scotia Consumer Advocate. January 2017.

Computation and presentation of rate effects. Consistency of assumed plant operation and replacement power costs. Control of total cost of small projects. Coordination of information-technology investments. Investments in biomass plant with uncertain future.

317. **N.S. UARB** Matter No. M07746, NS Power Enterprise Resource Planning project, Nova Scotia Consumer Advocate. February 2017.

Estimated software project costs. Costs of internal and contractor labor. Affiliate cost allocation.

318. **N.S. UARB** Matter No. M07767, NS Power Advanced Metering Infrastructure projects, Nova Scotia Consumer Advocate. February 2017.

Design and goals of the AMI pilot program. Procurement. Coordination with information-technology and software projects.

319. **Québec** Régie de L'énergie R-3876-2013 phase 3A; Gaz Métro estimates of marginal O&M costs; Regroupement des organismes environnementaux en énergie. March 2017.

Estimation of one-time, continuing and periodic customer-related operating and maintenance cost. Costs related to loads and revenues. Dealing with lumpy costs.

320. **N.S. UARB** Matter No. M07718, NS Power Maritime Link Cost Recovery, Nova Scotia Consumer Advocate. April 2017.

Usefulness of transmission interconnection prior to operation of the associated power plant.

ACRONYMS AND INITIALISMS

APS	Alleghany Power System
ASLB	Atomic Safety and Licensing Board
BEP	Board of Environmental Protection
BPU	Board of Public Utilities
BRC	Board of Regulatory Commissioners
CC	Corporation Commission
CMP	Central Maine Power
DER	Department of Environmental Regulation
DPS	Department of Public Service
DQE	Duquesne Light
DPUC	Department of Public Utilities Control
DSM	Demand-Side Management
DTE	Department of Telecommunications and Energy
EAB	Environmental Assessment Board
EFSB	Energy Facilities Siting Board
EFSC	Energy Facilities Siting Council
EUB	Energy and Utilities Board
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
LRAM	Lost-Revenue-Adjustment Mechanism
NARUC	National Association of Regulatory Utility Commissioners
NEPOOL	New England Power Pool
NRC	Nuclear Regulatory Commission
OCA	Office of Consumer Advocate
PSB	Public Service Board
PBR	Performance-based Regulation
PSC	Public Service Commission
PUC	Public Utility Commission
PUB	Public Utilities Board
PURA	Public Utility Regulatory Authority
PURPA	Public Utility Regulatory Policy Act
SCC	State Corporation Commission
UARB	Utility and Review Board
USAEE	U.S. Association of Energy Economists
UC	Utilities Commission
URC	Utility Regulatory Commission
UTC	Utilities and Transportation Commission

PLC 4/14/2017

North American Performance-Based Regulation for the 21st Century

Three analyses may prove useful to utility-industry stakeholders as performance-based regulation evolves over the coming years. One measures average long-run total factor productivity growth for U.S. electricity distributors. The second surveys PBR plans from the U.S. and Canada for the past two decades. The third suggests ways in which regulators can incorporate ''trackers'' into PBR plans to deal with particular and ongoing cost items not traditionally covered by PBR plans.

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I. Introduction

Performance-based regulation (PBR) arose with both the wave of utility privatizations that began in the United Kingdom (UK) in the 1980s and the search around the same time for more effective ways of regulating prices for the rapidly changing telecommunication industry. A principal focus of PBR is to provide an alternative to traditional cost-based regulation. With their longstanding—and somewhat similar—institutional regulatory histories, traditional regulation in the United States and Canada meant that regulated prices could only normally change as the result of time-consuming and disruptive base rate cases where all costs and billing quantities were up for grabs. PBR permits regulated prices to change without a base rate case, lengthening what is

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commonly known as "regulatory lag." Lengthened regulatory lag subjects regulated utilities to the type of incentives experienced by company managements in competitive industries, where a company's cost savings or profitable extra sales increase earnings. We extend our discussion of the history of and rationale for PBR in Section II.

One of the most contentious elements of PBR formulae is the *X-factor*—not because stakeholders disagree on whether it should be part of the PBR formula (it almost always is), but because they disagree on at what it should equal. So, what *should* it equal? A standard practice is to base *X-factors*, in part, on long-run industry-wide total factor productivity (TFP) growth. Calculating TFP growth to be used as the basis for an *X-factor* requires a high-quality, transparent, and uniform source of data that is readily available to the parties of regulatory proceedings. Such data are collected by the U.S. Federal Energy Regulatory Commission (FERC) for electricity and combination electricity/gas utilities in its "Form 1." We used Form 1 data to calculate TFP growth over the years 1972 to 2009. We found that during this period the weighted average TFP growth for our 72 U.S. electricity distributors was 0.96 percent. Calculations that estimate average productivity over a relatively long period—such as ours—can serve as a benchmark for *X-factors* in PBR plans. Details of our productivity calculation and its relevance to PBR plans appear in Section III.

The extent to which PBR transmits incentives to utility managements is critically dependent on the transparency, stability, and objectivity of the formula that governs price movements between base rate cases. This formula is typically driven by several key components, including a productivity or "X" factor, an inflation factor, and an exogenous or "Z" factor. Other typical components include earnings sharing mechanisms and service-quality provisions. In addition, some jurisdictions have included pass-through items for specified costs as "Y" and/or "K" factors. We review these plan components in Section IV.

Lengthened regulatory lag subjects regulated utilities to the type of incentives experienced by company managements in competitive industries.

In Section V, we discuss a growing practice—"trackers"—that we believe could be used with PBR to facilitate efficient recovery of qualified expenditures. Section VI concludes.

II. Origins of PBR

As a method of regulating prices, what is known as PBR in North America arose in the UK in the 1980s. Subsequent to helping start the worldwide trend in privatization, the UK also popularized a method of tariff regulation in water, electricity, gas and telecommunications called "RPI-*X*" or "price cap" regulation.[1] According to Armstrong *et al.*:

> First applied to British Telecom (BT) in 1984, RPI-*X* regulation now exists for British Gas (BG), British Airports Authority (BAA), the regional water companies, and, in the electricity industry, the National Grid Company and the regional distribution and supply companies. [note omitted] Almost fifty firms in Britain are subject to RPI – *X*, and the system has attracted considerable international interest.[2]

Following its popularity in the UK, price cap regulation was adopted in the United States for AT&T in 1989 and for gas and electricity companies in the United States and Canada subsequently.

The application of somewhat similar PBR pricing formulae, however, mask to a large extent the considerable underlying institutional differences upon which price regulation was based in the UK (and other jurisdictions that looked to the UK for regulatory guidance, such as Australia and Argentina). It is well known that neither the UK nor the other jurisdictions that began regulation with the

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UK-inspired privatization efforts have the constitutional, accounting, and administrative institutions that define regulation in Canada and the United States.[3]

Probably the most useful way to signal that the institutions upon which basic regulation is based are quite different in Canada and the United States than abroad concerns the source of the *X-factor*. In current practice in both the UK and Australia, the *X-factor* does not come from a TFP growth study but rather is a way to synchronize current prices (or revenues) with long-term economic forecasts (up to 8 years, depending on the formula period) of capital and operating costs.

Such forecasts of long-term costs are contrary to the ''known and measurable'' standard that lies at the base of utility regulation in North America.[4] Ofgem (the UK regulator), in a recent price review, backed out the *X-factor* as the value that would permit current prices to trend toward the forecasted costs for electricity distributors in 2015.[5] Australia defines its *X-factor* the same way, as the method of truing-up projected costs with projected revenues during the formula period.[6] In neither case does the *X-factor* relate to a measure of industry productivity growth, as such, and in both cases the transition of regulated prices over the formula period follows forecasts of the type that we believe no regulator of energy utilities in the Canada or the United States has ever countenanced.

III. Productivity Trends among U.S. Utilities

We calculate TFP for a population of 72 U.S. electricity and combination electricity/gas companies from 1972 to 2009, using the distribution component of the electricity business. The population includes companies of different sizes and located in different parts of the United States reflecting a wide diversity of geography, development, and age.

Such forecasts of long-term costs are contrary to the 'known and measurable' standard that lies at the base of utility regulation in North America.

All the data are both publicly available from FERC and other sources and of a highly standardized form suitable for a broad-based and objective TFP study.[7] FERC Form 1 data is filed annually by jurisdictional U.S. standalone electricity and combination electricity/gas companies. Form 1 provides financial and operational information and can be accessed independently and checked by any interested party.

Productivity growth is specified, by definition, as the *difference* between the *growth rates* of a firm's physical outputs and physical inputs. That is, to the extent that a firm's productivity grows, it will transform its inputs into a greater level of output. Thus, the task of productivity measurement involves comparing a firm's outputs and inputs over time. ''Total'' factor productivity measures all of a firm's inputs and outputs, employing advanced theoretical techniques to combine disparate inputs and outputs into single input and output indexes suitable for comparison to one another.

Because a company produces different types of outputs and uses different types of inputs, a TFP study needs to combine those disparate measures into well-defined output and input indexes. Index number theory provides reliable procedures for doing so.[8] In this article, output, input and TFP indexes are constructed using the Tornqvist/Theil index methodology for the various components of outputs and inputs.[9] We create individual TFP indexes and growth rates for each company for each year. We then calculate a weighted average TFP index and growth rate for each year, using the company's total MWh for each year as weights.[10]

Our TFP measurements span the period 1972 to 2009 with certain data series for capital additions and retirements

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reaching back to 1964—the earliest date for electronic Form 1 data. Since the rate of growth of TFP is defined as the difference between the growth rates of inputs and outputs, the annual TFP growth for any company is affected by annual changes in inputs (changes in capital investment or labor utilization) and outputs (the introduction of new services or changes in service demand growth). For this reason, TFP growth analysis should span a sufficient number of years to mitigate the effects of the business cycle or other idiosyncratic swings inherent to these factors.[11] Major capital replacements, for instance, would have the immediate effect of reducing measured TFP because the investment appears as an unusually large annual capital expenditure without a corresponding change in demand. Over time, however, replacement of the old capital is likely to increase productivity growth because it embodies new technology to serve demand more efficiently. The more years of data that are added, the more the effects of year-to-year changes in TFP growth are moderated and a picture of long-term productivity growth emerges.

For PBR plans to work well, reliable methods for determining the elements of the key formulas for price changes must exist. The efficiency incentives for regulated firms inherent in PBR plans are based on the value of long-term regulatory commitments, which in turn depend on the reasonableness and objectivity of the data and analysis used in their formation. Only changes in long-run average cost affect, for example, the equilibrium prices in a competitive market (from which the incentives inherent in PBR plans are drawn). Short-run changes in productivity—even industry-wide changes in productivity—do not cause firms to enter or leave an industry.

Productivity growth rates for individual firms, on the other hand, vary greatly from year to year. The TFP growth results that we present demonstrate this high degree of short-term variability (**Figure 1**).[12] Given this high degree of variability and the fact that short-run fluctuations do not affect the long-term picture for competitive firms, a constant productivity target is preferable to a variable target given the underlying theory which draws productivity studies into PBR plans.

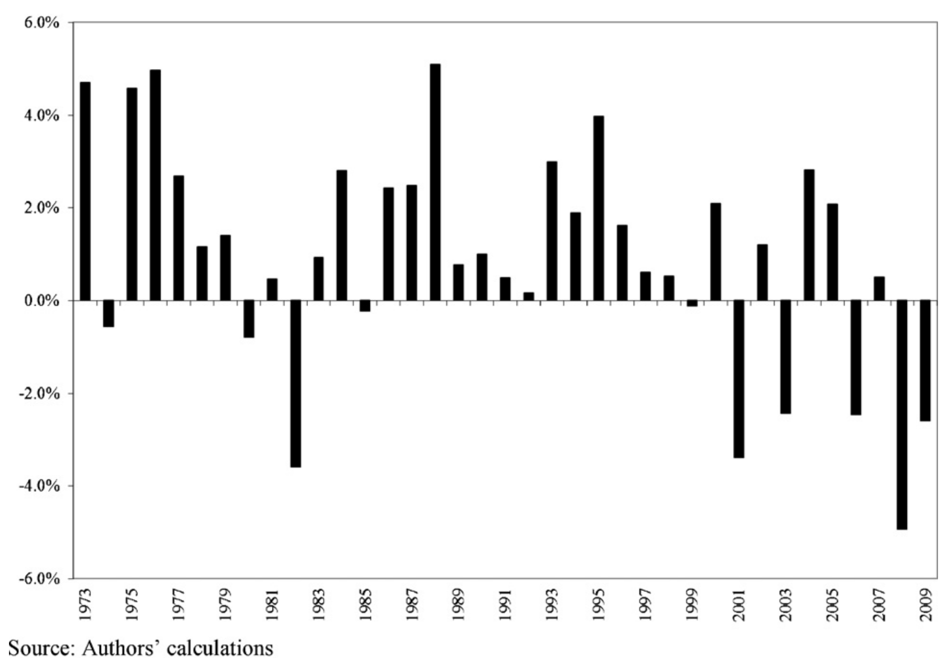

Figure 1: TFP Growth of U.S. Utilities, by Year

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Unless there is reliable proof to the contrary, the best and most supportable economic assumption is that while productivity growth may fluctuate in an erratic short term, or longer-term cyclical fashion, from time to time, it will eventually revert back to its long-term, underlying trend. This basic view of long-term trends has been adopted by many academic researchers who have studied macroeconomic time series such as GNP, prices, wages, unemployment rates, money stock, interest rates, etc.

With respect to the measure of output, there are two considerations. The first is whether one measure tops others in capturing the output for energy distributors that perform varied kinds of services with a multitude of capital facilities. The second question is whether it would be useful to include various sorts of outputs (kWh or numbers of customers) into a single output for measuring TFP. We use kWh as the measure of output. We conclude that if a single measure is chosen, it is the most representative of the nature of the utility, the size of its system, and its revenues. Of course, in a recession or in response to a price shock, sales may decline with a distribution system that is otherwise unchanged—thereby seeming to show a decline in productivity growth for other reasons. On the other hand, a rising use per customer for a utility with a fully penetrated service territory (as in an urban area) may well show larger inputs over time for a static customer output—also seeming to show a decline in productivity growth for other reasons. It remains the case that for an energy delivery business where much of the cost is tied up in long-lived capital, there are trade-offs in using one imperfect measure of output or another. The theory underlying PBR does not help in the choice—only practicality. Our preference has always been to use kWh with the longest time series that Form 1 permits so as to dampen the effects of the kind of short-term or cyclical patterns that would most influence kWh sales as a measure of output.

The theory underlying PBR does not help in the choice—only practicality.

Figure 1 depicts our TFP estimates. For the complete period, the weighted average TFP growth for U.S. utilities is 0.96 percent. TFP growth fluctuates considerably year to year and in more recent years exhibits sharp declines. The fastest TFP growth occurred in 1988 at 5.09 percent while the slowest TFP growth occurred in 2008 at −4.93 percent.

IV. PBR in the United States and Canada

There is a reasonable history among regulators in the United States and Canada regarding the parameters that become part of PBR plans.

A. Overview of PBR regulatory precedent

Table 1 presents a summary of those plans.

For Canada, we list PBR plans for various firms in Alberta, British Columbia, Ontario, and Quebec. In the United States, we list plans employed in California, Maine, Massachusetts, and Oregon. In Canada, the plans were rather evenly split between price and revenue caps; price caps were the dominant type of PBR plan in the United States. Consumer price indexes were the most common inflation factor in Canada, while the Gross Domestic Product Price Index (GDP-PI) was dominant in the United States. Almost all plans were comprehensive (i.e., applying to all costs), with only three examples of plans pertaining only to operation and maintenance costs. The *X-factors* were positive or non-negative in all cases. Almost all plans had a *Z-factor* and some had various versions of pass-through provisions in

?Table 1: Cap-Based PBR Precedents for North American Energy Utilities

Country	Province/ State	Company	Service covered[1]	Cap Type	Start Year	Term (years)	Cost Scope[2]	X Factor	Includes Stretch Factor?	Inflation[3]	Flow through provisions / Y Factor?	Capex provisions / K Factor?	Z Factor?	Earnings Sharing Mechanism	Re-openers/ Off-ramps?	Service Quality Provisions	Source[4]
Canada	Alberta	ENMAX Power	Electricity T & D	Price	2007	7	Comprehensive	1.2%	Yes	Canadian EU CPI / Alberta Average Hourly Earnings, 50/50 weighting	Yes[1]	Yes[1]	Yes	50-50 for excess earnings	Yes	Penalties	1
	British Columbia	Terasen Gas Inc.	Gas D	Revenue	1998	3	Comprehensive	2.0%-3.0%	No	CPI-BC	Yes[2]	Yes[2]	Yes	50-50, no deadband	No	Annual review only	2
			Gas D	Revenue	2004	4	Comprehensive	50%-66% of Inflation	No	CPI-BC	Yes[3]	No	Yes	50-50, no deadband	Yes	Various standards and incentives	3
		Fortis BC	Electricity G, T & D	Revenue	1996	4	Comprehensive	3.0-4.0% (O&M), 2.0% (Capex); 0% for all costs in last year	No	CPI-BC (O&M), CPI-Canada (Capex)	Yes[4]	Yes[3]	No	50-50, no deadband	Annual review	Assessment only	4
			Electricity G, T & D	Revenue	2000	3	Comprehensive	2.0%	No	CPI-BC	Yes[5]	Yes[4]	No	No	ND	ND	5
			Electricity G, T & D	Revenue	2007	2	Partial (O&M)	2.0%	No	CPI-BC	No	NA	Yes	50-50, no deadband	Annual review	Financial incentives	6
	Ontario	Enbridge Gas	Gas D	Revenue	2000	3	Partial (O&M)	1.1%	Yes	CPI-Ontario	No	NA	Yes	No	Yes[1]	Yes	7
			Gas D	Revenue	2008	5	Comprehensive	Implicit in inflation	NA	GDPPI-Canada•A; 0.45 ≤ A ≤ 0.60	Yes[6]	Yes[5]	Yes	50-50 sharing of excess earnings	Yes	No	8
		Union Gas	Gas D	Price	2001	3	Comprehensive	2.5%	No	GDPPI-Canada	Yes[7]	No	Yes	50-50 sharing around deadband	Yes	Penalties	9
			Gas D	Price	2008	5	Comprehensive	1.8%	No	GDPPI-Canada	Yes[8]	No	Yes	Variable/asymmetric sharing of excess earnings	No	No	10
		Ontario electricity distribution companies	Electricity D	Price	2000	3	Comprehensive	1.25%	Yes	IPI	No	No	Yes	50-50 sharing of excess earnings	No	No explicit financial incentives	11
			Electricity D	Price	2007	3	Comprehensive	1.0%	No	GDPPI-Canada	No	No	Yes	No	No	No	12
			Electricity D	Price	2010	3	Comprehensive	0.9-1.3%	Yes	GDPPI-Canada	No	Yes[6]	Yes	No	Yes	Reporting requirements only	13
	Quebec	Gaz Metro	Gas D	Revenue[1]	2000	5	Comprehensive	0.3%	No	CPI-Quebec	Yes[9]	No	Yes	Variable sharing of excess/deficient earnings	Yes	Rewards & penalties	14
			Gas D	Revenue[1]	2007	5	Comprehensive	0.3%	No	CPI-Quebec	Yes[10]	No	Yes	Variable sharing of excess/deficient earnings	Yes	Rewards & penalties	15
U.S.	California	PacifiCorp	Electricity G, T & D	Price	1994	3	Comprehensive	1.4%	No	IPI	Yes[11]	No	Yes	No	No	Rewards & penalties	16
		San Diego Gas & Electric	Electricity and gas G, T & D	Revenue	1994	5	Partial (O&M)	0.9-1.1%[1]	No	IPI	No	Yes[7]	Yes	Variable/asymmetric sharing around deadband	Yes	Rewards & penalties	17
			Electricity and gas D	Price	1999	3	Comprehensive	1.1%-1.4%	Yes/No	IPI	Other*	No	Yes	Variable/asymmetric sharing around deadband	Yes	Penalties	18
		So. Cal. Edison	Electricity T & D	Price	1997	5	Comprehensive	1.2%-1.6%	No	CPI	No	No	Yes	Variable/asymmetric sharing around deadband	Yes	Penalties	19
		So. Cal. Gas	Gas T & D	Revenue	1997	5	Comprehensive	2.1%-2.5%	Yes	IPI	Other**	No	Yes	Variable/asymmetric sharing around deadband	Yes	Penalties	20
	Maine	Bangor Gas	Gas D	Price	2000	10	Comprehensive	0.5%[2]	No	GDP-PI	No	No	No	50-50 sharing of excess earnings	No	No	21
		Bangor Hydro Electric	Electricity D	Price	1998	3	Comprehensive	1.2%	No	GDP-PI	Yes[12]	No	Yes	50/50 sharing around deadband	No	No	22
		Central Maine Power	Electricity T & D	Price	1995	5	Comprehensive	0.5%-1.0%	Yes	GDP-PI	Yes[13]	No	Yes	50/50 sharing around deadband	No	Penalties	23
			Electricity D	Price	2001	7	Comprehensive	2.0%-2.9%	No	GDP-PI	No	No	Yes	50-50 sharing below specified earnings level	No	Penalties	24
			Electricity D	Price	2009	7	Comprehensive	1.0%	No	GDP-PI	Yes[14]	Yes[8]	Yes	Yes, 50-50 sharing above 11% ROE	No	Penalties	25

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Country	Province/ State	Company	Service covered[1]	Cap Type	Start Year	Term (years)	Cost Scope [2]	X Factor	Includes Stretch Factor?	Inflation [3]	Flow through provisions / Y Factor?	Capex provisions / K Factor?	Z Factor?	Earnings Sharing Mechanism	Re-openers/ Off-ramps?	Service Quality Provisions	Source [4]
U.S.	Massachusetts	Berkshire Gas	Gas D	Price	2002	10	Comprehensive	1.0%	Yes	GDP-PI	No	No	Yes	None	No	No	26
		Blackstone Gas	Gas D	Price	2005	5	Comprehensive	0.5%	No	GDP-PI	No	No	Yes	50-50 sharing around deadband	No	Penalties	27
		Boston Gas	Gas D	Price	1996	5	Comprehensive	1.5%	Yes	GDP-PI	No	No	Yes	75-25 shareholders-ratepayers sharing around deadband	No	Penalties	28
			Gas D	Price	2004	5	Comprehensive	0.4%	Yes	GDP-PI	No	No	Yes	75-25 shareholders-ratepayers sharing around deadband	No	Penalties & rewards	29
		Columbia Gas of Mass.	Gas D	Price	2006	10	Comprehensive	0.5%	Yes	GDP-PI	No	No	Yes	75-25 shareholders-ratepayer sharing around deadband	No	Penalties & rewards	30
		NSTAR Electric	Electricity D	Price	2007	7	Comprehensive	0.5%-0.75%	Yes	GDP-PI	No	No	Yes	Deadband with 50-50 sharing	Yes	Penalties & other incentives	31
	Oregon	PacifiCorp	Electricity D	Revenue	1998	3	Comprehensive	0.3%	No	GDP-PI	Yes[15]	No	Yes	Deadband	No	Penalties & rewards	32

[1] "G" stands for "generation," "T" for "transmission," and "D" for "distribution."
[2] "Comprehensive" means the cap applies to all costs/rates; "partial" means the cap only applies to some costs/rates.
[3] "IPI" is any utility- or utility-industry-specific price index
[4] See Table A-1.

This sample does not include so-called "stair-step" plans or plans with only rate freezes.
This sample only includes plans with X factors.

Notes - X factor
[1] Stated X factor is implicit in SDG&E's "growth/productivity adjustment"
[2] Only applies to second half of plan.

Notes - re-openers/off-ramps:
[1] Off-ramp can be requested by company.

Notes - flow through provisions / Y Factor:
[1] For SAS rates in the distribution tariff, TAC Deferral Account, and AESO load settlement costs
[2] "Cost of Defined Required Incremental Activities" (not specified) plus a variety of deferral accounts
[3] Various deferral accounts
[4] Flow through of "variations in property tax, capital tax and AFUDC from the target costs"
[5] Recovery of "extraordinary" O&M expenses, flow through of variances from forecasted income tax rates, and deferrals of regulatory and other small misc. costs
[6] For adjustments for weather impacts on average use in addition to "[r]outine adjustments" including expenses for DSM, CIS, upstream gas, upstream transportation and storage, and tax changes, and various deferral accounts.
[7] For gas-related costs and changes related to ROE
[8] For adjustments for weather impacts on average use in addition to "[r]outine adjustments" including expenses for DSM, CIS, upstream gas, upstream transportation, and storage, and various deferral accounts
[9] For weather impacts and interest rates; plus a variety of "exclusions" which are "basically under [Gaz Metro's] control"
[10] For impacts of weather, interest rates, tax rates, and volumes; plus a variety of "exclusions" which are "basically under [Gaz Metro's] control"
[11] For changes in accounting of DSM and taxes
[12] True ups for misc. expenses related to power purchasing
[13] For DSM, accounting changes, Electric Lifeline Program, and a few misc. items
[14] For accounting, regulatory, or tax changes, plus a deferral account for tree trimming
[15] For DSM
* Tree-trimming and some other misc. costs are excluded from SDG&E's rate indexing mechanism and appear to be recovered through balancing accounts.
** Some costs, such as "catastrophic event costs, environmental remediation costs, low-emission vehicle program costs, mandated social program costs, and regulatory transition costs" are recovered outside of the PBR mechanism.

Notes - cap type
[1] Not a pure revenue cap. Also includes a revenue requirement.

Notes - capex provisions / K factor:
[1] For transmission rates, includes a "G" factor which accounts for prudent investments in transmission growth. Plan also includes a municipal rider for capital "requirements" for distribution operations, with an annual maximum of $15 million.
[2] "Capital Efficiency Mechanism" and allowance for Commission approval of certain capital additions.
[3] Can apply for recovery of "extraordinary" capex
[4] Recovery of "extraordinary" capex
[5] Flow through of incremental capex related to attachment of natural gas-fired power generation projects, classified as Y factor
[6] Incremental Capital Module Materiality Threshold--necessity of capital-related rate relief determined through formula.
[7] Separate cap for capital-related revenue
[8] Price cap adjusted for net capital gains/losses

Y-factors and *K-factors*. Almost all had some form of earnings sharing. Most had some sort of reward/penalty for service quality. We describe all of the above plan elements in more detail in the next section.

B. Features of PBR plans

PBR plans, as reflected in Table 1, typically adjust revenues or prices by the following items:

$$\textit{Inflation} - \textit{X-factor} \pm \textit{Z-factor} \pm \textit{ESM} \pm \textit{SQ}$$

where *ESM* is an earnings sharing mechanism, and *SQ* is a service quality incentive. Other, less-common items include *K-factors* and *Y-factors*.

1. *Inflation*

An inflation index should be exogenous, reasonably reflecting the cost behavior facing the industry. It should also be based on publicly available information, frequently updated, transparent and easy to understand. There is rarely any particular contention surrounding the inflation component of PBR plans, as objective and reliable price indexes are readily available both for input and output prices. While the most common inflation index used in PBR plans is the GDP-PI (for either Canada or the United States depending on the location of the plan), using a weighted average of input prices is not

	ROR Range	α
A	6.4-10.0	0.00
B	10.0-13.0	0.50
C	> 13.0	0.75

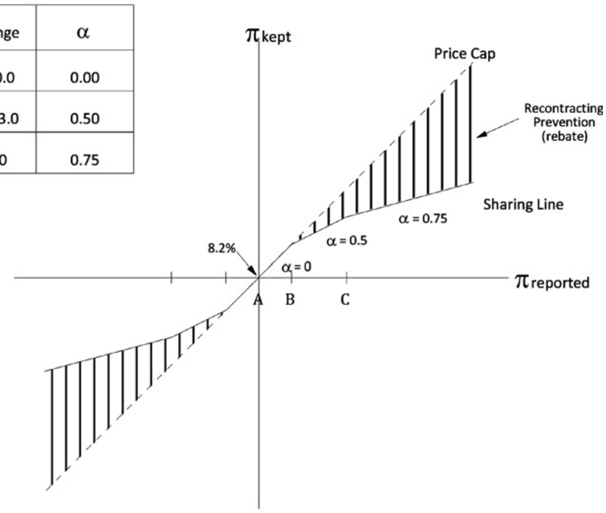

Figure 2: *Ex Post* Profit Sharing

uncommon. Five of the 30 plans surveyed have utility or utility-industry-specific input price indexes.

2. *X-factor*

For PBR plans in North America, the *X-factor* draws the most attention—precisely because reasonable expectations about the future prospects for productivity growth in any industry are difficult to predict objectively. Such is the reason why regulators often enough rely on index number studies to gauge productivity growth. Those productivity growth studies require the meticulous gathering and processing of large data sets and are reasonably costly to perform. But they have a solid scholarly foundation that pre-dates their use for PBR plans, and they are capable of being readily updated in the future rate cases that such PBR plans call for. Most of all, such productivity growth studies are *objective*—a preeminent requirement given the money at stake over the multi-year runs of PBR plans and the role of the regulator as a quasi-judicial arbiter of the traditional clash of interests between utility investor-owners and the public served by those utilities.

Almost all of the *X-factor*s that we surveyed were positive; none were negative. Plan *X-factor*s averaged around 1 percent, which is close to our long-run TFP growth estimate.

3. *Z-factor*

Z-factors typically account for *force majeure* events and have a materiality threshold, which specifies how much (in dollars) the event must impact the utility in order to be passed through to rate holders as a *Z-factor* addition. Regulators commonly use *Z-factors* to protect utilities against

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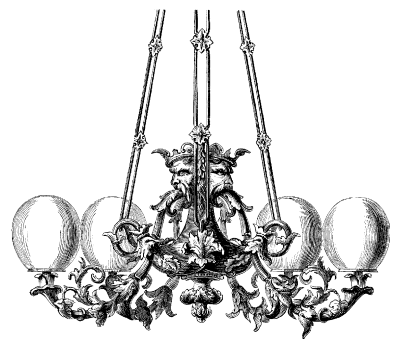
material events outside of their control—just as competitors in an industry would all adjust prices for exogenous cost changes that affect them all.

Over 90 percent of the plans had *Z-factors*. The *Z-factors* here were not identical—some allowed for the pass through of different events than others—but in general the plans permitted utilities to recover the costs of unforeseeable events with material impacts.

4. *Earnings sharing*

Earnings (or profit) sharing mechanisms can lend stability to a PBR regime, particularly one that is in its first generation. The stabilizing effect of earnings sharing can be depicted as in Figure 2. (This is purely an illustration. Actual capital costs for utilities in the United States and Canada are higher.) The shaded area is the size of the rebate. The rebate dampens both the company's profits and losses. This dampening effect grows as the reported profits deviate by a greater degree from the allowed return. The cost of earnings sharing is that, to the extent sharing is in effect (i.e., outside the dead band), it dampens the incentives of a company to innovate to cut costs and expand sales. That is, some efficiency incentives are given up in return for a more stable regime. In the figure above, the sharing line slopes upward, but at a decreasing rate as we move away from the origin (denoting that the sharing percentage increases). At expected profit levels, little or no sharing takes place and companies have full incentive to maximize profits. As profits increase, the level of sharing increases as well. The shape of this sharing line can help to provide natural stability for PBR plans. Our survey finds that a little less than one half of the PBR precedents had ESMs



with 50-50 sharing. A little over one-third had deadbands within which no deviations from the approved ROE would be shared with customers. Others had variable sharing (e.g., 60-40 or 25-75), sharing of all earnings above or below a certain ROE, or sharing of only excess earnings (i.e., earnings above a certain ROE).

5. *Re-openers/off-ramps*

Under certain circumstances, the PBR plan may warrant amendments or termination before the end of the term of the plan. Such conditions can be triggered by ''re-openers'' (for plan revision) or ''off-ramps'' (for plan termination). Re-openers and off-ramps are common aspects of incentive plans.

6. *Service quality*

A combination of rewards and penalties for service quality is a useful part of a PBR regime. PBR is driven by a belief in the power of profit incentives. To safeguard against reductions in service quality, we would suggest that a PBR plan include balanced rewards and penalties—which dominate among North American PBR plans.

7. *K-factor*

PBR plans have in some instances included provisions that flow through ''extraordinary'' or ''incremental'' capital expenditures into rates. Such provisions are known as *K-factors* and help ensure that utilities recover costs for necessary and prudent system upgrades. However, *K-factor* provisions can dampen efficiency incentives and are generally *not* included in PBR plans. Of course, utilities must make capital expenditures to continue to operate in a safe and reliable manner. However, these expenditures can be treated in a manner better targeted than an encompassing *K-factor*. Numerous regulatory bodies have adopted infrastructure trackers (see Section V) for specific capital expenditures, and that is the approach we would recommend. The capital expenditures

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that are candidates for such trackers must be comparatively unusual and narrowly defined (such as cast-iron pipe replacement for gas distributors or specific aged infrastructure replacement for electric distributors).

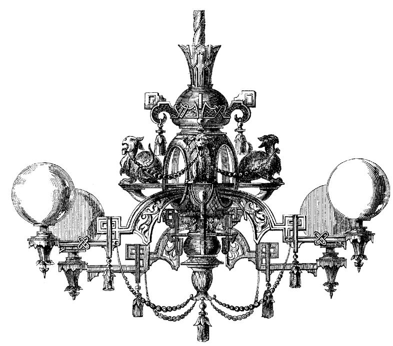
8. Y-factor

Y-factors give a utility pre-approval to recover routine costs that are beyond management's control. About half of the plans we surveyed contained *some Y-factor* items. The items varied widely across plans. Example cost items included demand-side management, tree-trimming, and expenses potentially arising from accounting or tax changes. Like *K-factors*, *Y-factors* can potentially reduce a utility's incentive to efficiently manage costs.

V. The Growth of 'Trackers'

North American regulators will undoubtedly continue to experiment with PBR over the next decades. And they should—PBR can and has allowed for improvements over traditional cost-of-service regulation. But what innovations can we add to PBR to create even better regulatory regimes? To answer, we highlight one innovative practice—the use of ''trackers''—that we believe could be coupled well with PBR.

Both *K-factors* and *Y-factors* have more or less similarity to automatic adjustments, or more colloquially ''trackers,'' in the context of ratemaking. Because we think that there is merit in asking for certain kinds of tracked cost recovery, even if not in the context of a PBR plan as such, we think it is useful to describe such



plans as have developed recently among regulators in the United States.

Commissions have traditionally used automatic adjustment clauses to allow retail rates to change because of fuel/gas cost changes or taxes:

> Adjustment clauses typically are allowed for exceptional expenses, such as fuel or purchased gas by a LDC, and occasionally taxes other than income taxes, where the particular costs are a major element of the overall costs of the utility, fluctuate widely, and are outside the utility's control.[13]

More recently, regulatory commissions have adopted other adjustment clauses to allow for the recovery of specific investments outside a normal rate case, and capital trackers are such an example. Capital trackers allow a regulated firm to recover qualified investments more quickly and efficiently than in a normal rate case. Trackers are used in various situations where the typical regulatory rate case provides an inadequate mechanism to adjust rates in response to increased investment in infrastructure. Capital trackers help ensure that the company in question has the financial standing necessary to invest in infrastructure needed to provide efficient, safe, adequate, and reliable service to its customers, in both good markets and bad, both now and in the long run. The objective of a cost-recovery mechanism is to reverse the regulatory lag associated with infrastructure investment. **Tables 2 and 3** contain several examples of trackers used for electric and natural gas utilities, respectively.

The basic idea of a capital tracker is to recover the costs of ''qualified investments''—a classified, pre-approved set of infrastructure investments incurred between rate cases. A tracker does not include all infrastructure investments, rather only infrastructure investments that meet the classifications set at the on-set of the tracker; all other infrastructure investments are

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Table 2: Examples of Electric Recovery Mechanisms for Qualified Investments

	State	Company	Tracker Name	Eligible Investments
1	Arkansas	SWEPCO	Generation Recovery Rider	Rider allows recovery of costs associated with the Stall generating facility that has received a certificate of environmental compatibility and public need issued by the Arkansas Public Service Commission
2	California	Southern California Edison	Advanced Metering Infrastructure Balancing Account	Expenditures up to the total authorized funding level of $1,633.5 million are deemed reasonable and the revenue requirement associated with those expenditures shall be recovered through the SmartConnect (Advanced Metering Infrastructure) without any after-the-fact reasonableness review
3	Colorado	Public Service Company of Colorado	Transmission Cost Adjustment	Rider to recover ongoing costs, other than operating and maintenance costs, associated with incremental transmission investments
4	Iowa	MidAmerican Energy	Cooper Tracking Mechanism	Additions Tracker provided a mechanism for recovery of the amount of Cooper Nuclear Station capital expenditures filed with the Iowa Utilities Board for recovery through the application of the tracker
5	Louisiana	Cleco Power	Infrastructure and Incremental Costs Recovery	The Infrastructure and Incremental Costs Recovery Mechanism applies only to Acadiana Load Pocket Transmission Project.
6	Missouri	Atmos Energy	Infrastructure System Replacement Surcharge	The infrastructure system replacement surcharge (ISRS) covers only a part of the expenses that the Company must incur to maintain and upgrade its system and to relocate facilities in connection with local, state and federal public improvement projects
7	NJ	Public Service Electric and Gas	Solar Loan II Program	Allows the Company to recover costs to install 51 MW of solar on homes, businesses and municipal buildings
8	Ohio	Duke Energy Ohio	Infrastructure Modernization Rider	Infrastructure Modernization to recover increased costs for maintaining and modernizing the distribution system, including Smart Grid investments and a $9 million investment in an electronic bulletin board to enable Duke and alternative power suppliers to post market prices for consideration by consumers
9	Oklahoma	Oklahoma Gas and Electric	Smart Grid Rider	Tariff Rider to recover up to $20 million of capital O&M costs related to company-proposed SmartPower deployment of 42,000 smart meters in Norman, OK
10	Pennsylvania	PPL Electric Utilities	Renewable Energy Development Rider	Recover costs associated with installing a device or devices not exceeding 10 kW which are, in the Company's sole judgment, a bonafide technology for use in generating electricity from qualifying renewable energy installations

Source: Company Tariffs.

Table 3: Examples of Gas Recovery Mechanisms for Qualified Investments

	State	Company	Tracker Name	Eligible Investments
1	Georgia	Atlanta Gas Light	Pipeline Replacement Program	The Atlanta Gas Light Pipeline Replacement Program is a 15-year project to replace more than 2,300 miles of bare steel and cast iron natural gas pipeline in Georgia. Each year in the fall, the Georgia Public Service Commission reviews the company's infrastructure replacement expenses from the previous year and then approves the new surcharge amount
2	Illinois	Peoples Gas Light and Co	Rider Incremental Cost Recovery	Peoples Gas Light & Coke's tracking mechanism for investments related to gas main replacement programs was authorized in 2010 and implemented in 2011. The program covers replacement mains and related appurtenances such as services, meters, regulators, measuring and regulating stations, city-gate check stations, and other ancillary infrastructure
3	Indiana	Vectren North	Distribution Reliability Adjustment	North (Indiana Gas) received approval to implement a tracking mechanism that allows the utility to defer expenses associated with investments in infrastructure replacement projects. Vectren defers the recovery of depreciation expense and property taxes and continues to utilize the allowance for funds used during construction (AFUDC) for 4 years from the date that each replacement was put in service
4	Massachusetts	Bay State Gas	Targeted Infrastructure Factor	Columbia Gas of Massachusetts (formerly Bay State Gas) received approval of its Targeted Infrastructure Reinvestment Factor (TIRF) as part of its last base rate case in October 2009. The TIRF allows for the recovery of the revenue requirement associated with bare steel capital additions for the previous calendar year, including: mains, services, service tie-ins, meters, meter installations, regulators, and industrial measuring and regulating equipment
5	Massachusetts	National Grid	Targeted Infrastructure Factor	The Massachusetts Department of Public Utilities (DPU) issued a decision in a rate case for National Grid Massachusetts companies Boston Gas, Essex Gas and Colonial Gas. The DPU adopted targeted infrastructure recovery factors for the companies. The TIRFs provide for the recovery of costs associated with the accelerated replacement of gas mains and the companies are allowed to surcharge customers up to 1% of total revenue
6	Michigan	SEMCO	Capital Infrastructure Investment Automatic Adjustment Mechanism	This mechanism will enable SEMCO Energy to recover the incremental capital-related costs associated with the accelerated removal and replacement of cast iron and unprotected steel service lines and mains

  http://dx.doi.org/10.1016/j.tej.2012.04.013

Table 3 (*Continued*)

	State	Company	Tracker Name	Eligible Investments
7	Nebraska	All NG Utilities	NA	The ISRS allows the rates of a gas utility to be adjusted twice per year to provide for the recovery of costs of eligible infrastructure system replacements
8	New Hampshire	National Grid	Cast Iron Bare Steel Replacement Program	New Hampshire – National Grid New Hampshire - Energy North Natural Gas Energy North Natural Gas has had a Cast Iron Bare Steel (CIBS) Replacement Program for several years
9	Texas	Atmos Energy Corp.	Bare Steel Pipe Replacement Program	This rate is designed to recover costs related to the Company's steel service line replacement program. A risk-based approach will be adopted to allow replacement of the highest priority steel service lines within this time period
10	Utah	Questar Gas	Infrastructure Replacement Adjustment	The Utah Public Service Commission authorized Questar Gas to implement a three-year pilot Infrastructure Replacement Adjustment (IRA) mechanism to track and recover between rate cases the costs associated with the replacement of high-pressure natural gas feeder lines. (1) Age and performance of existing pipeline (e.g., vintage steels, seams, welds and coatings). (2) Reconditioned pipe (i.e., refurbished and reinstalled pipe). (3) Operating and maintenance history. (4) Pipeline safety compliance

Source: Company Tariffs.

recovered in the company's next rate case proceeding. Typically, the proposed accounts included in a capital tracker go beyond the scope of routine investments required to support existing infrastructure. The definition of ''qualified investments'' varies; for example, the definition for People's Gas looks at qualified additions that have not been included in rate base associated with replacing aged facilities.[14] The definition of ''qualified'' infrastructure investments is tailored to the specific needs of the company.

The typical review process for a capital tracker varies by jurisdiction and the type of infrastructure tracker in question. Some trackers are subject to prudence reviews in the case of cost overruns. In other cases, no adjustments are made if costs are higher than originally anticipated in the budget, and the company is forced to suffer from the cost overrun. In between these extremes are mechanisms in which the variation between the budgeted amount of the investment and the actual expenditure is shared between the company and its customers. Finally, some investments may require review processes in order to ensure program effectiveness. Trackers for Smart Grid investments, for example, often employ penalty/rewards that encourage effective investment and use of the smart grid system.

VI. Conclusion

While by no means a universal practice, PBR plans that utilize measures of industry productivity continue to help various jurisdictions in the United States and Canada avoid the frequency and disruptions of traditional base rate cases. The elements of those PBR plans have themselves become rather traditional, with the typical plan components—

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inflation, *X-factors*, *Z-factors*, and earnings sharing—having changed little over the past decade. Complementing these traditional PBR components in helping to economize on traditional base rate cases is the growing practice of inserting ''trackers'' into rate formulae. Such trackers, which make good sense for those jurisdictions that have adopted them, target the inclusion of particular well-defined categories of costs. Particularly in the case of aged infrastructure, such infrastructure costs would otherwise require continuing and costly base rate inquiry.

Appendix A

See Table A.1.■

Table A.1: Sources for Table 1

1.	Alberta Utilities Commission Decision 2009-035
2.	British Columbia Utilities Commission Order No. G-85-97
3.	British Columbia Utilities Commission Order G-51-03
4.	British Columbia Utilities Commission Orders G-73-96, G-123-98
5.	British Columbia Utilities Commission Order G-134-99
6.	British Columbia Utilities Commission Order G-58-06
7.	EBRO 497-01, Decision with Reasons
8.	Ontario Energy Board Decision 2007-0615; Ontario Energy Board Nov. 1, 2011 Letter to All Registered Participants in EB-2011-0052
9.	Ontario Energy Board RP-1999-0017, Decisions with Reasons
10.	Ontario Energy Board 2007-0606 Decision Approving Settlement; Ontario Energy Board Nov. 1, 2011 Letter to All Registered Participants in EB-2011-0052
11.	Decision with Reasons, Ontario Energy Board RP-1999-0034
12.	Ontario Energy Board-2006-0089, Dec. 20, 2006 Report
13.	Report of the Ontario Energy Board on 3rd Generation Incentive Regulation for Electricity Distributors, Jul. 14, 2008; Ontario Energy Board-2007-0673, Sep. 17, 2008 Supplemental Report
14.	Régie de l'énergie Decision 2000-183
15.	Incentive mechanism agreed by the Task Force in NSP Phase 2 - R-3599-2006
16.	California Public Utilities Commission Decision 93-12-016
17.	California Pubic Utilities Commission Decision 94-08-023
18.	California Pubic Utilities Commission Decision 99-05-030
19.	California Public Utilities Commission Decision 96-09-092
20.	California Public Utilities Commission Decision 97-07-054
21.	Maine Public Utilities Commission Docket No. 97-795, Order Approving Rate Plan
22.	Maine Public Utilities Commission Docket No. 97-116, Order on Reconsideration
23.	Maine Public Utilities Commission Docket 92-345, Detailed Opinion and Subsidiary Findings, Jan. 10, 1995
24.	Maine Public Utilities Commission Docket 99-666 Order Approving Stipulation, Nov, 16, 2000
25.	Maine Public Utilities Commission Dockets 2007-215 and 2008-111, Order Approving Stipulation, Jul. 1, 2008
26.	Massachusetts Department of Telecommunications and Energy Docket 01-56
27.	Massachusetts Department of Telecommunications and Energy Docket 04-79
28.	Massachusetts Department of Public Utilities 96-50 and 96-50-C (Phase I)
29.	Massachusetts Department of Telecommunications and Energy Docket 03-40
30.	Massachusetts Department of Telecommunications and Energy Docket 05-27
31.	Massachusetts Department of Telecommunications and Energy Docket 05-85
32.	Public Utility Commission of Oregon Order No. 98-191

  http://dx.doi.org/10.1016/j.tej.2012.04.013

Endnotes:

1. The economic literature uses various synonymous terms for price cap regulation. Other terms include CPI-X regulation, RPI-X regulation, and performance-based ratemaking (PBR).

2. M. ARMSTRONG, S. COWAN AND J. VICKERS, REGULATORY REFORM: ECONOMIC ANALYSIS AND BRITISH EXPERIENCE (Cambridge, MA: MIT Press, 1994), at 165.

3. K. Gordon and J. Makholm, Allowed Return on Equity in Canada and the United States, at 32-34. See: http://www.cga.ca/pdfs/NERA.pdf.

4. ''An agency is justifiably skeptical of budget cost estimates as a basis for ratemaking. It will rely on test period results to adjustment for known or reasonably expected changes.'' Leonard Saul Goodman, *The Process of Ratemaking*, Vol. I, Public Utilities Reports, Inc., Vienna, VA, 1998, at 281.

5. Ofgem (2009) on the electricity distribution price control for April 2010 to Mar. 2015 (Distribution Price Control Review 5). Reference 149/09, Dec. 7, 2009. Starting on p. 57 of that report, which is available online, are the tables for each electricity distribution business, showing how the *X-factor* in its regulatory formula is calculated. It shows a forecast of costs in prices of 07/08, and the *X-factor* that achieves the same revenue as costs with a smoothly rising trend (''profiled'') from year to year. See: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=371&refer=Networks/ElecDist/PriceCntrls/DPCR5.

6. ''The *X-factor* must be designed to equalise (in terms of net present value) the revenue to be earned by the Distribution Network Service Provider from the provision of standard control services over the regulatory control period with the provider's total revenue requirement for the regulatory control period.'' See Australian national rules for electricity distribution (Ch. 6, National Electricity Rules), clause 6.5.9, entitled ''The *X-factor*.'' The report can be found on the Australian regulator's Web site, www.aemc. gov.au.

7. In addition to using FERC data, we use data from the U.S. Bureau of Economic Analysis, the U.S. Labor Department, Statistics Canada, the Handy-Whitman Index of Public Utility Construction, and data compiled by the following financial service firms: Standard and Poor's, Bloomberg, Moody's, and Barclays.

8. *See*: e.g., D.W. Caves, L.R. Christensen and W.E. Diewert, *The Economic Theory of Index Numbers and the Measurement of Input, Output and Productivity*, ECONOMETRICA 50:6 (1982), at 1393-1414.

9. *See*: L.R. Christensen, D.W. Jorgenson and L.J. Lau, *Transcendental Logarithmic Production Frontiers*, REV. ECON. & STAT. (1971) 55:1, at 28-45. The authors developed a particular flexible functional form called the ''translog.'' This is a second-order function. The superlative index number that is exact to the translog functional form is the Tornqvist/Theil index.

10. One use of this approach can be found in the doctoral dissertation of Jeff D. Makholm, Sources of Total Factor Productivity in the Electricity Industry, 1986 Univ. of Wisconsin-Madison (''Makholm Dissertation'').

11. With approximately 20 data series for 72 companies over 38 years, the database for our study contains over 50,000 ''data points.'' We reviewed the data to identify any anomalies and determined that some data points were sufficiently extreme to consider replacement. Although in each instance the data point could be traced back to the original FERC data, in 110 cases we decided that the data points were too extreme to be correct. For these data points, we extrapolated from nearby data points to estimate new numbers.

12. Much of this variability simply reflects how utilities book their costs. An individual examination of the year-to-year TFP growth rates shows many examples of countervailing positive and negative TFP growth numbers reflecting the particular decisions of when costs were booked to FERC accounts—a source of volatility that smooths out over time.

13. Goodman, *supra* note 4, at 1207.

14. The program defines qualified investments as ''replacement mains and related appurtenances such as services, meters, regulators, measuring and regulating stations, city-gate check stations, and other ancillary infrastructure.''

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Petition of NSTAR Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy for Approval of an Increase in Base Distribution Rates for Electric Service Pursuant to G.L. c. 164, §94 and 220 C.M.R. §5.00	)	D.P.U. 17-05

AFFIDAVIT OF PAUL L. CHERNICK

Paul L. Chernick does hereby depose and say as follows:

I, Paul L. Chernick, certify that the direct testimony and exhibits submitted on behalf of the Cape Light Compact in the above-captioned proceeding, which bear my name, were prepared by me or under my supervision and are true and accurate to the best of my knowledge and belief.

Signed under the pains and penalties of perjury.

Paul L. Chernick
President, Resource Insight, Inc.

Dated: April 27, 2017