PROVINCE OF MANITOBA

BEFORE THE PUBLIC UTILITY BOARD

Manitoba Hydro 2017/18 & 2018/19)
General Rate Application)

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

GREEN ACTION CENTRE

Resource Insight, Inc.

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I. Identification and Qualifications

Q: Mr. Chernick, please state your name, occupation and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honour society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

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, integrated resource planning, the cost-effectiveness of prospective new 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 professional qualifications are further summarized in Exhibit GAC-PC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than two hundred and fifty times on utility issues before regulators in thirty U.S. jurisdictions and five Canadian provinces. My previous testimony is listed in my resume.

Q: Have you testified previously before this Board?

A: Yes. I testified in the following proceedings:

- the 2008/09 general rate application ("GRA") of Manitoba Hydro ("MH," "the Company" or "Hydro"),
- Hydro's 2008 Energy-Intensive Industrial Rate proceeding,
- Hydro's 2010 GRA,
- Hydro's 2012 GRA,
- the 2014 review of the need for and alternatives to the Keeyask hydro-electric plant and other facilities, and
- the Board's 2016 Cost of Service Methodology Review.

II. Introduction

Q: On whose behalf are you testifying?

A: My testimony is sponsored by Green Action Centre ("GAC").

Q: What is the purpose of your direct testimony?

A: My sponsors have asked me to review three areas of Hydro's filings: marginal costs, rate design (considering both efficiency and affordability) and the Cost-of-Service Study. I review Hydro's estimates of marginal costs in the context of their use in rate design. My review of these issues is consistent with the Public Utility Board's concern about inefficient pricing and environmental emissions:

> The Board seeks to assure itself that MH's rate design and rates are consistent with the pursuit of the environmental objectives of The Sustainable Development Act (SDA). Energy efficiency presents the potential for a virtuous circle, wherein lower domestic consumption results in reduced customer bills, higher MH aggregate net export revenue and net income, and lower carbon emissions by MH's American export customers. (PUB Order 117/06, p. 3)

The Board (along with other parties) has expressed concern that rapidly rising rates will disproportionately burden low-income, high energy-use customers, and that some rate designs that encourage energy conservation (particularly inclining block rates) may further burden those customers, especially where natural gas is not available. I therefore propose changes in rate design to promote more efficient energy use while avoiding undue burden for lower-income households and those heating with electricity.

In connection with these topics, I also testify on the shortcomings in Hydro's documentation of its analyses and on the information available about Hydro's marginal costs.

III. Reviewability of Manitoba Hydro's Proposals and Analyses

Q: Has the Company provided adequate documentation of its marginal cost analysis?

A: No. The Company refused to provide its marginal generation cost estimates disaggregated into capacity and energy and by season, as well as supporting analyses. This information is essential to evaluating the Company's rate design proposals and to developing alternatives.

Q: What is Manitoba Hydro's explanation for its refusal to provide documentation of its marginal generation cost estimates?

A: Hydro refused to provide any breakdown of its marginal generation estimates or its supporting analysis on the following grounds, arguing that the estimates were based on commercially sensitive information, in particular, the expected value of electricity exports:

> the generation marginal cost values, including the detailed breakdown of generation marginal cost values are derived from and are very closely related to the electricity export price forecast which is confidential and commercially sensitive information. (GAC/MH II-8a)

Q: Do utilities generally release the derivation of their estimates of marginal (or avoided) costs?

A: Yes. I cannot recall a similar situation in which a utility has so broadly refused to document its estimates of avoided costs.[1]

In New England, the regional avoided costs (excluding losses and T&D, which are added by individual utilities) are derived in a collaborative process (for which I have been one of the consultants in three of the five biennial rounds) of the electric and gas utilities, consumer representatives, environmental advocates, and regulators.[2] This work shows detailed avoided-cost projections. California has similarly derived avoided costs through a public process of comments and workshops. If Manitoba Hydro cannot

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[1]In some cases, utilities will request protected status for certain inputs, such as detailed forecasts of market prices, releasing that information only to parties who are not engaged in power trading. In more than 20 years of reviewing avoided-cost estimates, I cannot recall a situation in which the utility has refused to even break out generation energy from capacity costs.

[2]Most recently: Hornby, Rick, et al., March 2015. "Avoided Energy Supply Costs in New England: 2015 Report." Northborough, Mass.: Avoided-Energy-Supply-Component Study Group. This report provides detailed avoided-cost projections for electricity and natural gas.

develop reviewable avoided and marginal costs, the Board may need to establish a similar process in Manitoba.

IV. Estimate of Marginal Costs for Rate Design

Q: Why are marginal costs important for the Company's ratemaking?

A: Marginal costs indicate the value of load reductions and the cost of load increases. Those values are important in the design of rates (e.g., using marginal costs to set the tail block of an inclining block rate or to rebalance GS rates between demand and energy charges).

Q: Does the Company agree that rate design should reflect marginal cost?

A: Yes.

> An important consideration is that rate structures should provide appropriate price signals regarding the value of energy and should promote the efficient and economic use of energy. Efficient and economic use refers to the optimal use of energy, which is not necessarily the least possible consumption of energy.
>
> b) Conservation rates that are designed with a tail block priced significantly higher than marginal cost may not be optimal. Pricing marginal use in excess of marginal cost may reduce consumption below the optimal level that would theoretically be achieved by pricing at marginal cost. (Coalition/MH I-131)

Q: Has Manitoba Hydro provided its estimate of long-run marginal cost?

A: Yes. Hydro estimates long-run marginal cost (in 2016 dollars) to be 7.67 cents per kWh (Coalition/MH II-35a) at the distribution level and 6.64 cents per kWh at the transmission level (GAC/MH II-24b). This estimate consists of the following cost components:

- A marginal generation cost of 5.55 cents per kWh (excluding losses) (Tab 8).

- A marginal transmission cost of 0.49 cents per kWh (based on a marginal value of $42.33/kW/year divided over 8760 hours) (GAC/MH II-24b; GAC/MH I-39 Attachment, p. 27).
- A marginal distribution cost of 0.77 cents per kWh (based on a marginal value of $58.12/kW/year divided over 8760 hours). (Coalition/MH II-35a; GAC/MH I-39 Attachment, p. 47).
- Loss factors of 14% for distribution-level loads and 10% for transmission level loads.

A. Estimate of Marginal Generation Cost

Q: How does MH estimate marginal generation cost?

A: The marginal generation cost estimate consists of energy and capacity cost components determined by year and season. Even though the Company insists that rate design reflect marginal cost, it has refused to provide its generation estimate broken down by cost component or by season, even in the most aggregate levelized form:

> the generation marginal cost values, including the detailed breakdown of generation marginal cost values are derived from and are very closely related to the electricity export price forecast which is confidential and commercially sensitive information. (GAC/MH II-8a)

Nor would MH provide its forecast of generation capacity prices (GAC/MH II-8g). MH insists that, even in the most aggregate form, its marginal-cost estimates would be too detailed to be provided to intervenors. (PUB/MH I-131b, GAC/MH II-8a).

In addition, MH has provided only a summary description of its methodology (GAC/MH I-34; PUB/MH 1-131b; GAC/MH II-8a-n)

Q: Is it possible to develop efficient marginal-cost-based alternative rate designs without the information?

A: No. Seasonal price differentials, time-of-use rates, and inclining-block rates are inherently dependent on a projection (or at least a general understanding) of the composition of marginal costs. Given Manitoba Hydro's refusal to share major parts of its projections (including the underlying methodology), I have been able to make some adjustments to Hydro's marginal-cost estimate, to guide my rate-design proposals, but the scope of my review and corrections has been limited.

This hearing may leave the Board in an awkward situation, with the intervenors filing evidence based on their interpretation of MH's limited public information, while the IEC develops quite different information, based on the ability to review and correct MH's analysis.

Q: Does MH propose an alternative to providing marginal generation cost estimates and analysis to intervenors?

A: Yes. MH suggests that Surplus Energy Program rates provide a reasonable proxy for marginal generation cost:

> In response to the question as to how marginal-cost based rates may be considered in the event that this information is commercially sensitive, Manitoba Hydro suggests that it may be possible to rely on publicly available pricing from Surplus Energy Program rates that are approved each week by the PUB. Seasonal trends in pricing may be discerned from the 52 weekly rate Orders issued by the PUB, which are summarized on pages 5 through 7 in the Report to the Public Utilities Board – Surplus Energy Program, found at Appendix 9.9 of this Application. (GAC/MH II-8a)

Q: Can SEP prices provide a reasonable representation of Manitoba Hydro's marginal generation costs?

A: No. SEP prices are for interruptible energy, set weekly, without capacity. Marginal generation costs would include the costs of the higher-priced periods in which Manitoba Hydro interrupts SEP supply, as well as firm capacity and other costs of firming supply.

The SEP pricing also appears to be for relatively flat energy deliveries to industrial customers, rather than the weather-sensitive varying loads of residential and smaller general-service customers.

Q: How did Manitoba Hydro derive its estimate of marginal generation energy cost?

A: Hydro uses an in-house production-costing model (SPLASH) to simulate system operation of its generation system 35 years into the future (PUB/MH I-131b, GAC/MH II-8b), for two load cases: a base case and "decrement" case assuming a constant decrease in load over the year:

> The first simulation run is a base case, which corresponds to the IFF case. In order to determine marginal value, a second simulation is undertaken in which the load is reduced from the base case by a constant increment in each month for a total of 500 GWh over the year as an example. The net difference in production costs between the two simulations for each year of the study period is divided by the energy associated with the incremental load change to derive the marginal generation value in dollars per megawatt hour. (PUB/MH I-131b)[3]

[3] Note that Hydro says that the second simulation reduces load by an increment, which may mean that load is increased by an increment or decreased by a decrement. Also, Hydro says that the "increment" is constant in every month, which may mean that it is constant in every hour, or that the hourly load reductions are greater in February than in January (since February has fewer hours) or may mean something else. Again, MH fails to clearly describe its computations.

The simulation includes three areas outside Manitoba: Saskatchewan, Ontario and MISO. (GAC/MH II-8d)

Q: Have you identified any problems with MH's marginal generation energy cost methodology?

A: Since I have not been able to check any part of the actual analysis, my review is limited. However, based on what MH has said about its approach, I have identified issues:

- Assuming a constant load decrement through the year does not capture the costs imposed by retail load, which tends to be higher in high-priced intervals, such as the hottest summer days, the coldest winter days, and on-peak hours in all seasons.
- The cost incurred by an increment in retail load represents the loss of export sales that could have been made without the load increment. The additional export sales that result from a reduction in load (such as MH modeled) will tend to be lower than lost exports from a load increase. The best sales opportunities can be booked without the load decrement, and additional energy freed up by reduced retail load is likely to find a less lucrative market, or even be bottled up in Manitoba, for lack of transmission.

Q: Was the generation capacity cost estimate an output of its runs of the SPLASH production costing model runs, which MH considers to be so sensitive and confidential?

A: No. Hydro's estimates of marginal generation capacity cost were developed externally based on its forecast of the market value of capacity, which MH claims is also confidential:

> the information on the value of generation capacity comes from proprietary forecasts, thus all elements are considered confidential. (GAC/MH II-8(i))

Q: Did you request that the Company provide whatever non-confidential information it could provide on its generation capacity cost methodology and input assumptions?

A: Yes. In response, the Company insisted that since the electricity export forecast is confidential, everything about it is confidential (GAC/MH II-8i)

> …the information on the value of generation capacity comes from proprietary forecasts, thus all elements are considered confidential.

MH provided only the following vague description:

> The capacity value is based on the market value for capacity as contained in the electricity export price forecast for the Midcontinent Independent System Operator (MISO) market. The market value for generation capacity represents the fixed annual cost of securing new capacity in the MISO market based on the net Cost of New Entry (CONE). The net CONE value represents the annualized capital and fixed O&M costs of a new capacity resource (which may or may not be a SCCT) minus any annual operational profit that would have been achieved in the energy market. In the nearer term, the value of generation capacity is much lower than the net CONE due to the current over supply of generation capacity in the MISO market. (COAL/MH I-133a)

In other words, MH's forecast of capacity cost may or may not reflect MISO's CONE, which may or may not reflect the annualized cost of an SCCT.

Q: What would the market capacity costs to which Manitoba Hydro refers mean in terms of marginal costs?

A: The CONE for MISO Zone 1 (Minnesota, North Dakota, and western Wisconsin) was $258.32/MW-day, or $94.29/kW-year in the capacity auction for summer 2017. The clearing price was $1.50/MW-day, down from $19.72/MW-day in 2016.

Capacity at the CONE price, with a 12% reserve margin and 14% for losses to secondary, would account for some $13.7/MWh in marginal costs for a secondary customer with a flat load, or about $22.9/MWh for residential and small general-service loads with 60% load factors. With the 2016 clearing price, the secondary-voltage marginal cost would be under $2/MWh.

Q: What kinds of information about its generation capacity cost estimate should MH be able to provide?

A: MH should be able to provide the following kinds of information:

- How the capacity cost estimate takes into account the Manitoba Hydro system 12% planning reserve margin (GAC/MH I-35b).
- Whether generation capacity cost reflects the value of dependable or just opportunity power.
- The projected generation capacity need date assumed in the marginal capacity cost estimate.
- How MH developed its summer and winter generation capacity cost estimates in cost per kW and how these estimates combined to estimate annual capacity cost.

Q: Can you recommend a solution to non-reviewability of marginal cost estimates?

A: The Board should direct MH to use a marginal-cost methodology that is not extraordinarily confidential, which could be evaluated by intervenors and used in public debate on the formulation of rate design. There are methodologies widely accepted by other utilities that are reviewable by intervenors. Most utility marginal-cost studies are either entirely public documents or are available to intervenors under confidentiality agreements.

B. *Estimate of Marginal T&D Cost*

Q: What was the basis of MH's marginal T&D cost estimates?

A: Manitoba Hydro applies a One-Year Deferral (OYD) Method to a ten-year forecast of load-growth-related capital expenditures and system load growth for the period 2016/17 through 2025/26. The forecast of expenditures is derived from various of the Company's Capital Expenditure Forecasts (CEFs), including CEF14-1 for transmission and CEF15-1 for distribution. (GAC/MH I-39, p. 7, 33)[4]

For purposes of the study, the Company separates the expenditures for each function into two groups: the Major projects that exceed $2 million and Domestic items that consist of many smaller projects. The CEFs use different terminology, such as the use of a Base Capital category, complicating comparisons among documents.

The marginal cost study identifies the load-related portion of Major expenditures on a project-by-project basis (GAC/MH I-39, Table E.1; GAC/MH II- 188, Attachment), although in some cases, the "project" is actually a program of multiple projects in different locations.[5] All Major projects included have in-service dates within the 10-year planning period. For many projects (but certainly not all), the load-related portion in the

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[4] The Marginal Transmission Cost report also states on page 11 that it relies on CEF15-1; different capital forecasts are used for various parts of the distribution analysis.

[5] The Major projects used to estimate the load-related fraction of investments are not necessarily the same as the projects to which that faction is applied.

marginal-cost study is consistent with the portion of costs categorized as "capacity enhancement" in the project justification documents that MH provided in Coalition/MH I-173 Attachment 2 (for transmission) and Attachment 3 (for distribution).

Rather than using a forecast of the Domestic investments, Hydro's marginal-cost study uses the projected costs in a single year to estimate the percent of costs that are load-related. For transmission, MH assumes that level of Domestic expenditures will continue. I have not been able to determine how MH treated future Domestic distribution costs, since MH presents its capital forecast as a single number for each year.

Q: Have you been able to confirm MH's calculations?

A: Only approximately. MH has not provided its workpapers in electronic form, or provided the basis for the costs it uses. Hydro conducts its analysis in multiple steps, changing the underlying data between steps. In one step, Hydro estimates the percentage of costs that are load related, using one set of annual costs by project. In the next step, Hydro applies those percentages to a different set of annual costs, to derive an estimate of levelized marginal costs. The percentages that Hydro uses in the second step are not quite the same as those that it derives in the first step.

As a result of the complexity of Hydro's analysis, the lack of spreadsheet documentation, the absence of justification documents (or even a project list) for the projects used in the second step, and the inconsistencies within Hydro's analysis, I cannot follow the multiple steps from the justification documents and the Capital Expenditure Forecast data to the computation of the load-related percentage and the total annual investment, and thus to the costs in $/kW-year.

Q: What problems have you identified with the analysis of the major projects, common to the marginal transmission and distribution cost estimates?

A: I identified the following problems, in addition to the lack of clear documentation of the analysis:

- The analysis excludes the costs incurred before the planning period for major projects expected to be completed in the planning period. (GAC/MH II-19 (a)-(c)).
- There are almost no major individual T&D projects in the last 5 years of the planning period. While MH inserts various generic items, the planned expenditures in the latter half of the planning period are depressed, apparently because MH has not yet developed detailed plans for those years (GAC/MH I-39 Attachment, p. 14).
- MH categorizes some expenditures as being related to outages or to removal of aging but still useful equipment and unrelated to load, even though the justification documents indicate that the project would not be required without load growth. These costs are load-related and should be included in the estimate of marginal cost.
- Hydro converts the cost per kW-year into a cost per kWh for a flat load, with a 100% load factor, rather than a typical load shape by class. That load shape is not representative of most end uses, and certainly not of the average end uses for which Hydro's load forecast projects a 62% load factor (Appendix 8.1, Schedule 4.1). Revising MH's estimate of the marginal costs to reflect system load factor produces marginal transmission costs of 0.9¢/kWh and marginal distribution costs of 1.2¢/kWh. The marginal cost by rate class should be computed using the class load factor.

- MH did not include any marginal O&M costs for either transmission or distribution (GAC/MH I-40a).

Q: Does Hydro recognize that its analysis may understate marginal cost because it lacks committed projects in the latter half of the planning period?

A: Yes. Manitoba Hydro acknowledges that limited information regarding future budgets affects its marginal-cost estimates.

> Predicting future expenditures becomes more difficult when examining costs further out on the planning horizon. This may have some impact on the significantly lower planned expenditures in 2021/22 and 2022/23. Currently planned annual project expenditures within this time period fall within the $30 - $35M range. There may be additional projects, not yet identified, which may increase costs within this timeframe… (GAC/MH I-39 Attachment, p. 14)

A quick review of Hydro's CEF shows that it has indeed tended to understate expenditures beyond the next few years. For example, Table 1 shows that the 2013 CEF included transmission investments for 2017–2020 that were radically lower than the costs projected in the 2016 CEF. The understatement started just four years into the projection from the 2013 CEF.

Table 1: Comparison of Transmission Expenditure Forecasts ($M)

	2013	2016	Increase
2014	36		
2015	71		
2016	78		
2017	36	159	342%
2018	35	144	309%
2019	74	128	74%
2020	58	136	135%
2021	86	95	11%
2022	84	60	-28%

Q: Does Hydro attempt to adjust its analysis to correct for the relatively short time frame of T&D budgeting?

A: Yes, but only for the major transmission expenditures, not for distribution. To "more accurately represent final load-related costs" in the last three years, MH used a proxy cost equal to the average expenditure over the previous seven years. (GAC/MH I-39 Attachment, p. 14)

Q: Is this proxy a valid substitution for realistic ten-year projection of transmission expenditures?

A: No, for at least two reasons:

- The expenditures assumed in the last three years are essentially synthetic data, rather than actual cost projections and therefore should not affect the marginal cost estimates one way or another.
- An average of expenditures in the first seven years is likely to be an underestimate, since the plan of major transmission projects in the marginal transmission study includes only one project starting after the first year. (GAC/MH I-39 Attachment, p. 22–24)
- The expenditures listed in GAC/MH II-22d include only seven active individual transmission projects in 2019/20, and one each in 2020/21 and 2021/22.

Q: What is MH's justification for omitting T&D O&M from the estimate of marginal T&D costs?

A: MH argues that the effect of load growth on O&M is minor and difficult to estimate. According to the 2015 marginal transmission cost study,

> [T]he impact is small and incremental O&M due to a small change in demand is difficult to determine: it is estimated that including these costs may add approximately 1% to 2% in the avoided T&D costs. (GAC/MH I-39 Attachment, page 7)

Q: Does MH's argument have merit?

A: No. MH fails to recognize that the O&M associated with load-related projects is also load-related.

Manitoba Hydro is correct that demand does not increase most T&D O&M costs directly (although higher loads on line transformers, underground lines and overhead lines increases the failure rate of that equipment, and hence increases maintenance costs). Load-related additions of new substation, new transmission lines, and in many cases new feeders will increase maintenance costs.

I have not attempted to disaggregate the capital additions in the MH marginal T&D analysis between new equipment, replacements in kind, and so on, and then apply the system average ratio of O&M to gross plant or other measure of installed plant by type. At this point, it is clear that MH left a component out of its marginal-cost analysis, but not the magnitude of that omitted cost.

1. Marginal Transmission Costs

Q: Were some of costs of the transmission projects in MH's marginal-cost analysis incurred before the planning period?

A: Yes. Table 2 provides a comparison of expenditures in the planning period and in total on six major transmission projects that MH identified as 100% load-related in the transmission marginal cost study.

Table 2: Omitted Costs of Major Transmission Projects

	% Load-Related	Project Total Expenditure: Marginal Cost Study	Project Total Expenditure: CEF15 or CEF16
Rockwood East 230/115kV Station	100%	0.2	53.2
Winnipeg- Brandon System Improvements	100%	33.0	42.8
Brandon Area Transmission Improvements	100%	0.6	12.3
Southwest Winnipeg 115kV Improvements	100%	34.6	40.2
Stanley Station 230/66kV Transformer	100%	14.5	16.7
Lake Winnipeg East System Improvements	95%	36.8	66.9
Total Load-related Expenditures		***117.8***	***228.8***

These projects are about a third of the major transmission projects in MH's analysis.

Q: What is MH's rationale for excluding these expenditures?

A: The Company explained that "Manitoba Hydro does not include costs before year 1 as it is assumed they cannot be avoided." (GAC/MH II-19a)

Q: Is the Company correct in excluding the pre-2016/17 expenditures from the marginal cost analysis?

A: No. The key to providing customers with efficient pricing signals is to ensure that they face prices consistent with the long-term costs incurred due to load growth. The standard approach for estimating marginal cost of T&D is to estimate the investment required for a given amount of load growth, preferably over a period long enough to be representative. That period can be historical, projected, or a combination of both. It is not necessary to assume that specific projects will be eliminated or accelerated due to changes in load growth; the objective is to produce a reasonable estimate of the incremental cost per kW of load growth over the long term. MH includes all the load growth projected for 2015/16 to 2025/26, but only some of the costs projected for that period, and therefore understates the marginal cost.

It is clear that Hydro does not believe in its own justification for omitting the earlier-year costs of projects completed in its analysis periods. MH's analyses include costs expended in 2016/17, 2017/18 and in some places 2015/16, that cannot be avoided or accelerated by load reductions or increases that may occur in 2018/19 and beyond, in reaction to the rates implemented in this proceeding. There is no reason to omit part of the cost of projects that have or will meet the load growth in the analysis periods.

Q: Did MH properly identify the portion of major transmission project costs that are load-related?

A: Not in all cases. Hydro treats some costs of load-related projects as non-load related because the projects involve removal of older equipment or would have other benefit. This is true even where the justification for the project is entirely load-related. In addition, the project described as "Transmission Line Upgrade for NERC Alert" appears to be dominated by load-related line sag, yet MH includes only half the cost as load-related.

Hydro says that it cannot explain what portion of reliability-related costs were excluded from load-related costs because "the data are no longer available" (GAC/MH II-20g).[6]

Q: Did you recalculate MH's estimate of marginal transmission cost, reflecting adjustments to the treatment of major projects?

A: No. As I reviewed MH's transmission analysis, I realized that Hydro had made multiple offsetting errors. Important items—especially the NERC alerts—cannot be reviewed, given MH's failure to include these documents

[6] Oddly, the justification documents have some of the data that MH says are no longer available.

as part of its filing or as part of the marginal-cost studies provided in the first round of discovery.

Q: How does Hydro model non-major or "Domestic" transmission in the marginal-cost study?

A: Hydro used the estimated cost of the transmission Domestic program in a single year (2015/16), at $37.6 million, and assumes constant expenditures (in real terms) in the ten-year planning period, which may be a reasonable assumption, but it is odd that MH does not plan the Domestic projects for even a year in the future.

The problem in MH's treatment of the Domestic budget is in its decision that only projects classified as "Reliability: Load-Related" are load related. This category amounts to only $1.2 million or 3.3% of the total (GAC/MH I-39 Attachment, p. 13). Of the remaining, MH categorizes 59% as "Reliability: Outage-Related" and 30% as "Reliability: Import/Export-Related." Large portions of those categories are probably related to retail load. In the major projects, for example, import/export related items typically represent situations in which local retail loads constrain imports or exports; Manitoba Hydro treats those major projects as load-related, and should do the same for the Domestic projects driven by the same considerations.

Q: Has the Company documented the determination of the portion of domestic transmission expenditures that are load growth related?

A: No. Hydro provides no detail on which projects were excluded, or why.

Q: Given the multiple and sometimes offsetting errors in MH's analysis of marginal transmission costs, and the lack of data, how did you deal with this cost category in your analysis?

A: For the purposes of the present evidence, I have adopted Hydro's estimate of marginal transmission costs in $/kW-year or cents/kWh at a 100% load factor. I correct the load factor below.

2. Marginal Distribution Costs

Q: How did MH estimate the marginal cost of distribution?

A: As I described above, MH separately estimated the load-related portions of the major projects from one capital plant and the smaller "domestic" projects for a single year, averaged those percentages, and applied that percentage to another capital plan costs.

Q: How did MH estimate the load-related portions of the major projects

A: Hydro estimated load-related fraction of the major projects on a project-specific basis. Hydro asserted that it individually reviewed 100 projects (GAC/MH I-39 Attachment, p. 45), but provided information on only 69 projects, of which two are "Planning Items" for Winnipeg-area projects and distribution modernization (Coalition/MH I-174-Attachment 3).

Q: What information did MH provide regarding that review?

A: MH provided the projected capital investments for the 69 projects for 2015/16 through 2024/25, along with its assessment of the percentage of the cost of each project that was load-related (GAC/MH-II-22d). Hydro also provided justification documents for most, but not all, of the projects in Coalition/MH-I-174, Attachment 3. As I noted above, Hydro ignored the earlier expenditures on projects that were needed to meet load growth in the analysis period.

Q: Does MH properly designate the portion of each projects that is load-related?

A: No. The following examples indicate the nature of MH's errors:

- New St. Vital 115/24 kV substation, total cost $52 million, treated as 0% load related in GAC/MH-II-22d. The final justification document for this project reports that it is 60% for "Capacity Enhancement" (which is certainly load-related) and 40% for "Operational Enhancement" (COAL/MH-I-174, Attachment 3, p. 79). The language of the actual justification document indicates that the driving concerns are all related to current load exceeding the station's firm capacity:

  > The station's summer firm limit is 40MVA. Since the station's summer peak load has been recorded at 46MVA, if a bank were to fail under peak conditions, the remaining 6 MVA would need to be transferred to other stations using feeder ties. The existing feeder tie capacity that provides non-firm capacity to St. Vital Station distribution is tenuous. The area load is increasing due to new residential and commercial developments. In the summer of 2010, this capability did not exist under peak conditions as the area loading, was over the St. Vital Station non-firm limit….
  >
  > Justification is based on addressing the equipment rating concerns currently mitigated by station operating restrictions and customer-driven demand for electricity in the area, as well as restoring reliable station contingency plans.

- New McPhillips Station total cost $47 million, treated as 0% load related in GAC/MH-II-22d. The final justification document for this project reports that it is 60% for "Capacity Enhancement," 30% for "Operational Enhancement" and 10% for Employee Safety (COAL/MH-I-174, Attachment 3, p. 108). Again, the actual justification document indicates that the driving concerns related to current load exceeding the station's firm capacity:

> Peak summer loading at McPhillips Station is beyond firm capacity and requires the station banks to be operated in parallel to support voltage. The existing station equipment are underrated for parallel bank operation. This creates an unsafe operating situation causing concern or maintenance and operating staff. In the event of bank failure, load transfer to St. James Station via feeder ties is required to reduce station loading to firm capacity.
>
> Although feeder tie capacity exists, some customers have experienced low voltage under tied conditions. Station equipment dates back to the late 40's and experiences oil leaks.

- Anola DSC RM of Springfield, total cost $5 million, treated as 0% load related in GAC/MH-II-22d. The final justification document for this project reports that it is 100% required for reliability (COAL/MH-I-174, Attachment 3, p. 483). The justification document explains that the reliability problem arises from the loads on the Dugald and Oakbank substations, which were already at twice their firm load, operating near their maximum load with all equipment in service, and not backed up by feeder ties from other stations.

> [C]urrent capacity at Oakbank and Dugald station is not sufficient to supply increasing load in the area due to new development. Residential development in Oakbank and Dugald area is growing and is expected to continue as developers construct new houses in the area. Dugald station loading has grown at 3.7% in past ten years. Oakbank Station growth has been more significant at 4.5%. Both stations are winter peaking. The additional capacity will provide area firm capacity and accommodate future load growth in the Dugald, Oakbank and Anola communities.

In all three of these cases, and many more, MH has classified projects that are driven by load as being 0% load-related and omitted them from the marginal-cost study.

Hydro says that it excludes some costs identified as reliability-related because:

- Load growth isn't expected to increase the likelihood of outages.
- Reliability project values that are not directly load related are considered out of scope for the Distribution Marginal Cost Study. (GAC/MH II-22f)

Since the reliability issues are often driven by load, MH's explanation is incorrect.

Q: Did MH properly account for the costs of the projects meeting the 2016–2025 load growth that were expended prior to 2016?

A: No. Hydro made the same mistake that it did with transmission, by ignoring previous expenditures on projects needed to meet the load growth in the analysis period.

Q: How much did that decision affect MH's estimate of marginal distribution cost?

A: The full cost of the load-related major distribution projects was about 11.7% higher than the cost that MH recognized.

Q: Did MH explain how it estimated the portion of the Domestic projects that were load-related?

A: No. Hydro assumed that 50% of the cost of the Domestic projects was load-related, without any analysis of the nature of those projects or their driving factors. Hydro says both major and domestic project costs are not treated as load-related if they are "driven by factors other than load growth such as reliability or aging infrastructure." (GAC/MH I-39 Attachment, p. 37) As we can see in the major projects, costs classified as reliability or "aging infrastructure" are often load-related.

Q: Did MH properly divide the load-related distribution costs by growth in distribution load to estimate the marginal investment per kilowatt?

A: No. MH calculates marginal distribution cost per kW by dividing *distribution* expenditures by *system* load growth. This calculation is appropriate for transmission, which serves system load, but not for distribution. The load growth attributed to distribution expenditures should not include the transmission level load that is not served by the distribution system.

Q: What is the effect of including transmission level load in computing the marginal distribution costs?

A: By overstating the load growth driving those distribution investments, MH understates the cost of each kW of distribution load. About 17.5% of peak load is from large industrial customers served at greater than 30 kV (i.e., transmission voltage) (Appendix 8.5). Hydro forecasts that a similar group, called "Top Consumers" (comprising 23 or 24 customers, depending on which page of Appendix 7.1 one trusts) will grow at 1.2% from 2015/16 to 2025/16, compared to 1.4% for total sales. Combining these figures suggests that 15% of projected system load growth is due to the growth of customers served at transmission level.

C. Estimate of Environmental Costs

Q: How did Manitoba Hydro treat environmental costs in its DSM valuation?

A: Hydro increases DSM benefits by 10% to reflect environmental, societal and other non-energy benefits (GAC/MH I-20e). As Hydro explained in the 2010 GRA proceeding, the Company assumes that emissions costs are reflected in the export prices on which its marginal cost estimates are based:

> The avoided GHG and other emissions are implicitly valued in the determination of marginal cost because the forecast of export prices includes consideration of potential environmental costs that may be associated with electricity production in Manitoba Hydro's export markets. (2010 GRA, RCM/TREE/MH II-4 (b)(vii))

Q: Is it reasonable to assume that the sales prices for Hydro's non-firm opportunity exports reflect the value of carbon emissions?

A: No. The economy price estimates that Hydro derives from its SEP prices are primarily for sales to US utilities, which do not currently face carbon charges. The historical economy sales to Saskatchewan and Ontario also do not include the Federal government's carbon pricing plan, which Hydro describes in its fuel-switching analysis for PUB/MH I-129.

Q: How did Manitoba Hydro treat environmental costs in its fuel-switching analysis?

A: In its original analysis, Manitoba Hydro ignored environmental costs. In response to PUB/MH I-129, Manitoba Hydro ran comparisons that included environmental costs for gas combustion in Manitoba, but not for the additional greenhouse emissions in neighbouring regions due to reduced exports.

> The cost comparisons that include carbon pricing are based on the Government of Canada's $10 per tonne of CO2e in 2018 which increases by $10 per tonne annually to $50 per tonne in 2022. (PUB/MH I-129, p. 2)

Q: What generation sources do Hydro exports to MISO displace?

A: The major sources of marginal energy in MISO are coal (at about 900 kg CO_2e/MWh), combined-cycle gas (at about 350 kg/MWh) and gas-fired combustion turbines (about 500 kg/MWh).

In recent years, the combined-cycle and coal plants in northern MISO (MN, WI, ND, IA) have operated at a similar range of capacity factors, with most gas plants in the 20%–60% range and most coal plants in the 10%–80% range. Consequently both gas and coal would be at the margin at times. This conclusion is supported by a recent study that found that in MISO coal operated at the margin about 90% of the time and gas about 75% of the time.[7] It is not clear how the mix of marginal resources would vary by season (although gas prices tend to be higher in the winter) and gas may be more of the marginal mix in peak periods. Since some of the gas plants would operate to provide local support in load pockets, Hydro's exports may back down a rural coal plant even when an urban combined-cycle plant is operating. Over time, rising gas prices will tend to reduce the share of marginal energy that comes from the gas plants, while retirement of coal plants will tend to increase the marginal gas percentage. Overall, an estimate of 750-kg of CO_2 per MWh is reasonable for baseload sales.

Q: You have discussed the avoided emissions from existing MISO generation. Would the avoided emissions be similar if Hydro's export contracts avoid new generation?

A: The avoided emissions would be similar, but a little lower. New generation in Minnesota or Wisconsin would be primarily gas combined-cycle or combustion turbine. Those new units would operate similarly to the existing ones, and the mix of energy avoided by the contracts would be similar. For example, suppose that a Minnesota utility purchases 300 MW at a 70% capacity factor from Manitoba Hydro and defers a 300-MW combined-cycle

[7] Marginal Emission Factors Considering Renewables: A Case Study of the U.S. Midcontinent Independent System Operator (MISO) System; Mo Li, Timothy M. Smith, Yi Yang, and Elizabeth J. Wilson; *Environ. Sci. Technol.*, 2017, 51 (19), pp. 11215–11223. The sum of these two percentages exceeds 1.0 because the marginal resource varies by area within MISO.

plant that would otherwise have operated at a 50% capacity factor. The 1,850 GWh of annual hydro energy would result in the combined-cycle not being built or run, reducing generation from that unit by about 1,300 GWh. In the 20% of the year in which Hydro provides 550 GWh (and the combined-cycle would not have run), the marginal resource would be primarily coal. Thus, the avoided energy mix would be about 70% gas (1,300 ÷ 1,850) and 30% coal, for an avoided emission rate of about 510 kg of CO_2 per MWh.

The mix avoided would vary with the future system mix in MISO, and the relative prices of gas and coal. The effect of Hydro exports avoiding a new gas-fired plant would be essentially the same, whether the gas-fired plant is being added to meet load growth or to replace retiring coal capacity.

Q: Would the emission effects be similar if the contract facilitates the retirement of an existing coal unit?

A: No. In that case, the avoided output would be essentially all coal, and the avoided emissions would be on the order of 900 kg of CO_2 per MWh.

Q: How would these calculations differ if the power were sold to Saskatchewan, rather than to a US MISO utility?

A: The results for Saskatchewan would be similar. SaskPower's energy supply in 2016 was 40% coal (not counting the 4% of energy from Boundary Dam Unit #3, which has carbon capture for most of its emissions) and 36% gas.

Q: What environmental costs per MWh do these avoided emission rates imply?

A: The marginal avoided emissions are on the order of 500 to 900 kg per MWh. Multiplying those values by the $/tonne Federal carbon prices results in a marginal carbon cost of $5 to $9/MWh in 2018, rising to $25 to $45/MWh in 2022. Levelized over 10 years, starting in 2018 or 2019 those carbon prices would be \$19/MWh to \$39/MWh. I will use a value of \$29/MWh in computing marginal costs.

D. *Estimate of Marginal Cost by Rate Class*

Q: What are your best estimates of marginal costs by rate class?

A: I used the following marginal costs:

- Hydro's estimate of marginal generation costs of 6.2 cents per kWh at the generation level, plus losses
- a marginal transmission cost of \$42.33/kW-year, plus losses,
- a marginal distribution cost of \$69.80/kW-year, plus losses,
- a 2.9 cents per kWh adder to reflect environmental costs, plus losses
- loss factors of 10% for transmission level customers and 14% for distribution level customers,
- class load factors from the PCOSS18.

The results of these computations are set forth in Table 3.

Table 3: Marginal Cost (in cents per kWh) by Rate Schedule

Rate Schedule	G	T	D	Ext	Total
Residential	6.34	1.10	1.92	3.31	12.66
GS Small, ND	6.34	0.90	1.57	3.31	12.11
GS Small, D	6.34	0.84	1.48	3.31	11.96
GS Medium	6.34	0.77	1.34	3.31	11.75
GS Large (< 30Kv)	6.34	0.70	1.22	3.31	11.56
GS Large (30–100Kv)	6.10	0.59		3.19	9.89
GS Large (> 100kV)	6.10	0.59		3.19	9.89

Since MH also estimates the marginal generation cost per kWh for a constant load over all hours, rather than for a typical retail load shape, the marginal generation costs provided in Table 3 are understated for rate-design purposes.

Q: What is the significance of these results for rate design?

A: Hydro's marginal costs exceed proposed energy rates for all classes, even without correcting generation marginal costs for load shape, as summarized in Table 4.

Table 4: Comparison of Energy Rates to Hydro's Estimates of Marginal Costs

	Tail-Block Charges (cents per kWh)		**Marginal Cost**
	2017/18	*2018/19*	
Residential	8.556	9.232	12.7
GS Small, Non-Demand	4.117	4.442	12.1
GS Small, Demand	4.117	4.442	12.0
GS Medium	4.117	4.442	11.8
GS Large, Greater Than 30 kV	3.873	4.179	11.6
GS Large, 30–100 kV	3.600	3.884	9.9
GS Large, Less Than 100 kV	3.488	3.764	9.9

Thus, inclining-block rates and reduced demand and customer charges are needed to provide customers with appropriate marginal price signals.

V. Changes to Rate Structure

Q: What rate design does Hydro propose?

A: MH proposes equal percentage changes to all charges within rates for all rates.

Q: What rate-design changes do you address in this section of your testimony?

A: It appears that Manitoba Hydro will be requesting large rate increases to reflect spending on Bipole 3, Keeyask and other projects. These rate increases will be a burden to residential low-income customers and electric space heating customers. I propose discounted rates for both of those groups.

In addition, I propose an inclining-block rate to encourage residential energy conservation.

Because of data limitations, my proposed rates are only estimates. Manitoba Hydro can replace my estimates with updated billing determinants in its compliance filing.

A. *Affordable Rates for Low-Income Customers*

Q: What is the purpose of your proposal regarding low-income customer?

A: My intention is to develop a rate design for low-income customers that reduces their bills, while maintaining incentives for energy conservation. Specifically, I designed a rate based on estimates of the energy consumption of customers with incomes below 125% of the Statistics Canada's Low Income Cut-Off (LICO-125).

I relied on MH's 2014 Residential Energy Use Survey for the number of LICO-125 customers and their average annual usage.[8] That survey estimates that Manitoba Hydro has 142,124 LICO-125 customers, with an average annual usage of 14,484 kWh, compared to 16,422 kWh for non-LICO-125 customers.

Q: What discount rate structure do you propose for all LICO-125 customers?

A: Hydro could implement a rate for all LICO-125 customers that eliminates the customer charge and reduces the proposed energy charge by 4¢/kWh for the first 500 kWh/month, leaving the tail-block charge at the Company's proposed 8.556 ¢/kWh. I selected the 500 kWh first block because MH's bill

[8] I used the same source for the number and usage of heating and non-heating customers.

frequency analyses indicate that about 94% of residential usage was in bills over 500 kWh, so that most of that usage block is inframarginal. Even though the low-income customers would receive a discount on their bills, most of their energy decisions (to use more or less energy) would result in the customer facing the full retail energy rate.

Under this rate, LICO-125 customers using 500 kWh or more each month would save $341 annually; a customer using 250 kWh each month would save $221 per year. The average customer using less than 500 kWh uses 282 kWh; that average smaller customer would save about $237 annually. Assuming that the mix of LICO-125 bills above and below 500 kWh is the same as that for all residential bills (27% under 500 kWh, at an average of 282 kWh, and 73% over 500 kWh), the average benefit for low-income customers would be about $313 annually.

Q: Are the 4¢/kWh discount and the 500 kWh uniquely suitable for Manitoba Hydro low-income customers?

A: No. The magnitude of the discounts (in both the ¢/kWh discount and the number of kWh discounted) is a matter of judgment. The Board can scale my proposals up or down as desired.

Q: How would this rate design affect other customers?

A: Manitoba Hydro would lose about $44.5 million in revenues from my proposed LICO-125 discount. If that lost revenue were distributed over the non-LICO residential customers, the increase in the energy rate would be about 0.8¢/kWh.

Since the LICO discount is a social program, similar to low-income assistance supported by tax revenues, it seems more equitable to recover the discounts from all non-LICO customers. Spread out over all non-LICO sales, the revenue increase from this LICO discount would be 0.22¢/kWh.

Q: What position has MH taken on the implementation of discount rates for LICO customers?

A: Manitoba Hydro has expressed concern that rate discounts will expose the Company to excessive revenue risk, due to uncertainty regarding the number of customers eligible for a LICO-125 discount:

> …any attempts to set rates based upon estimates of LICO-125 participants and their respective level of energy usage would present an unacceptably high risk of revenue forecast error. (Appendix 9.14, pp. 17–18).

Hydro seems to be concerned that it will set rates assuming a particular mix of LICO and non-LICO sales, and that additional customers will sign up for the LICO-125 rate, resulting in the Company bringing in less revenue than planned.

Q: Do you agree that MH would necessarily be taking on excessive risk from a LICO-125 rate?

A: No. Hydro has many options for mitigating its revenue risk. First, MH files a rate request every two years, and can update billing determinants and revenue projections during the rate-setting process, so the mix of residential revenues are not likely to get very far out of sync with ratesetting.

Second, the revenue risk posed by an unexpectedly high enrollment in the low-income rate is probably much lower than the risk the Company faces from the normal sales variation from weather, the behaviour of large customers, and other factors.

Third, Hydro's ratemaking is not so much driven by rate-of-return (as it is with investor owned utilities), but by targets for retained earnings and debt/equity ratio. So a small under/over collection in 2018/19 will be recaptured in the rate case for 2019/20 and 2020/21.

Fourth, the Board could allow MH to implement some sort of formal revenue reconciliation, as many utilities in the United States do. This adjustment may be redundant with the setting of rates to achieve cumulative financial targets.

Fifth, if absolutely necessary, MH could propose and the Board could approve a limit on the number of eligible customers allowed onto the LICO-125 discount in each year. The allowance for the number of customers on the LICO-125 rate can be reset in each rate case.

Q: Does your proposal for a LICO-125 rate perfectly address the burden of rising electric rates on low-income customers?

A: No. It would be preferable to develop a rate structure and administrative structure to reflect the differences among low-income customers, in terms of income and energy use. Below, I discuss a rate design to reflect, at least approximately, the additional cost of space heating for low-income customers. Adding a climate-related adjustment to the space-heating allowance would be desirable, but would apparently require legislation.

Rather than applying a fixed discount allowance to each low-income customer, it would be preferable to vary the discounts to reflect the customer's income level, perhaps measured as a percentage of the Low Income Cut-Off for the household size.

I do not have enough data to develop such a rate. If the Board is concerned about energy affordability, even with my proposed LICO-125 rate, it should convene a stakeholder process, under the aegis of a Boardappointed facilitator, to move forward with a more sophisticated low-income rate.

B. *Affordable Rates for Heating Customers*

Q: Why is it appropriate for the Board to consider discount programs for residential customers with space-heating?

A: Even for customers with moderate income, electric space heating may create a significant financial burden. That concern has been raised as a reason not to implement conservation rates, since large customers are often space-heating customers. While most space-heating customers certainly have opportunities to increase efficiency and reduce use—and Manitoba Hydro should prioritize those large customers for comprehensive retrofits in the PowerSmart program— many space-heating customers have limited options for switching fuels and may face considerable barriers to massively reducing their space-heating use, even with financial support from PowerSmart.

Q: Have you designed a discounted rate for space-heating customers, using the LICO rate structure?

A: I examined the distribution of residential electric use among seasons, using the time-of-use data provided in MH's cost-of-service study. Specifically, I compared usage in other seasons to usage in the summer (with no space-heating load). I assumed that the annual heating use of an all-electric customer is 14,500 kWh, based on the difference between the average heating and average non-heating customer in the Residential Survey. As summarized in Table 5, I distributed that difference over the non-summer months using the cost-of-service study data, and proposed a discounted heating block of 100 kWh/month in the spring months of April and May, 250 kWh/month in the fall months of October and November, and 500 kWh/month in the four winter months.

Table 5: Seasonal Usage Pattern, Monthly kWh Over Summer Usage

	Months in Season	Monthly Excess Typical Heating Customer	Discounted kWh
Spring	2	450	100
Fall	2	1,200	250
Winter	4	2,800	500
Annual		14,500	2,700

My objective was to offset the cost of heating, without reducing incentives to conserve, by targeting the reductions to usage blocks that will not be the customer's marginal usage.

Q: How large a discount do you propose for the heating customers?

A: I suggest the 4¢/kWh discount that I proposed for low-income usage. The difference in the rates would be that the heating discount would vary by season. Each space-heating customer would receive a discount of 4¢/kWh on 2,700 kWh, or $108 annually. For the 180,402 heating customers identified in the Residential Survey, this would amount to $19.5 million.

Q: Does it matter that billing cycles do not align perfectly with the seasons?

A: Not much. As I understand it, the Company prorates old and new rates in billing cycles that overlap the date of a rate change. It is likely that Manitoba Hydro's billing system can do the same for the seasonal changes in discounted rates. But even if the billing system cannot deal with that proration, the seasonal transition is not a fundamental problem.

The annual discount will be the same, even if (for example) the fall discount is applied to some usage that actually occurred in the summer or winter. The date at which billings would be subject to the seasonal rate should be selected to maximize the portion of the billing periods for which the usage is in the ratemaking season. For example, with monthly billing, the seasonal rates would take effect on October 15, December 15, and April 15. With bimonthly billing, the effective billing dates might be November 1, January 1 and May 1.

Q: How would your proposals apply for LICO-125 customers with space heat?

A: I would simply add together the discounted energy allowances, so a LICO-125 heating customer would get 500 kWh discounted in the summer, 600 in the spring, 750 kWh in the fall, and 1,000 kWh in the winter.

Q: How would this rate design affect other customers?

A: Manitoba Hydro would lose about $44.5 million in revenues from my proposed heating discount. If that lost revenue were distributed over all non-LICO customers in all classes, the increase in the energy rate would be about 0.12¢/kWh.

C. Inclining Block Rates for Residential Customers

Q: Since you have found that the marginal costs of serving residential load is greater than Manitoba Hydro's proposed residential energy rates, what rate design do you propose for the residential class?

A: Yes. I have developed an inclining-block rate for general residential customers, consistent with the goal of providing efficient pricing signals to customers.

Q: If MH implemented inclining block rates for all residential customers, what would be the bill impacts?

A: As a very modest step, I developed an inclining block rate structure for non-LICO customers where all of the requested increase is recovered in the tail block energy charge with no increase to the 2016/17 customer charge and energy charge for the first 500 kWh at current levels, $7.82/month and 7.93¢/kWh. The residential survey reports that there are the 324,274 non-LICO customers, using an average of 16,422 kWh annually. The lower customer charge would reduce revenues by about $2.4 million (compared to a rate of $8.44/month) and the lower energy charge for the first 500 kWh would reduce rates by $10.7 million (compared to the proposed rate of 8.556¢/kWh), for a total of about $13.4 million. Recovering those revenues from the remaining non-LICO residential energy above 500 kWh/month would require that the tail-block rate be set at 0.365¢ higher than proposed rate, or 8.921¢/kWh.

Table 6 summarizes my rate proposals, based on the proposed August 1, 2017 permanent rates. The recovery rates (the increased energy rate for other customers) are shown for the LICO-125 rate and the non-LICO space-heating rate. The cost of the LICO-125 space-heating rate is included in the other two discount proposals.

Table 6: Summary of Rate Proposals

	MH proposed	LICO-125 All	Non-LICO ESH	LICO-125 ESH	Non-LICO Residential
Basic Charge	$8.44	$0	$8.44	$0	$7.82
First Block	8.556¢	4.556¢	4.556¢	4.556¢	7.93¢
Remainder	8.556¢	8.556¢	8.556¢	8.556¢	8.909¢
First Block kWh					
Summer	—	500	—	500	500
Spring	—	500	150	650	500
Fall	—	500	250	750	500
Winter	—	500	500	1,000	500
Recovery rate		0.22¢	0.12¢		

Q: What additional measures can be taken to mitigate residential rate impacts?

A: To the extent possible, Manitoba Hydro should attempt to mitigate bill effects on heating customers through effiency, rather than discounts. Specifically, Hydro should develop a PowerSmart program to ensure that new electrically-heated homes are super-insulated and use the most efficient applicable heat pumps, dramatically reducing heating costs. Eligibility for the discounted heating tariff by new customers should be conditioned on participation in the superinsulation program. In addition, Hydro could also use an aggressively marketed high-incentive PowerSmart program to retrofit superinsulation, envelope sealing and heat pumps for the existing heating customers, allowing the heating rate to be phased out.

D. Demand Charges

Q: How should the Board instruct Manitoba Hydro to design rates for the classes with demand charges?

A: The Board should require that Manitoba Hydro reduce the demand charges over time and increase energy charges.

Q: Why is it appropriate to shift demand revenues to energy?

A: There are two such reasons. First, the energy charges of demand-metered customers are significantly below marginal cost. These customers are not being given useful incentives to conserve energy. Second, demand charges do not provide appropriate incentives to conserve, even during high load hours.

Q: Please explain why demand charges do not provide the appropriate incentives.

A: Demand charges are a particularly ineffective means for giving price signals, for the following reasons:

- The demand-charge portion of the electric bill is determined by the customer's individual maximum demand. Capacity costs are driven by coincident loads at the times of the peak loads on the system or various types of T&D equipment, not by the non-coincident maximum demands of individual customers. The customer's individual peak hour is not likely to coincide with the peak hours of the other customers sharing a piece of equipment, especially since the peaks on the secondary system, line transformer, primary tap, feeder, substations, sub-transmission lines, and transmission lines occur at varying times. In fact, Hydro acknowledges that T&D capacity is driven by diversified demand, not the sum of individual customer maximum demands (GAC/MH II-14).
- Demand charges provide little or no incentive to control or shift load from those times which are off the customers' peak hours but which are very much on the generation and T&D peak hours. Customers can avoid demand charges merely by redistributing load within the peak period. Some of those customers will be shifting loads from their own peak to the peak hour on the local distribution system, on the transmission peak, or on the peak load hour of Manitoba Hydro, thereby causing customers to increase their contribution to maximum or critical loads on the local distribution system, the transmission system, or the regional generation system.

- Demand charges are difficult to avoid; even a single failure to control load results in the same demand charge as if the same demand had been reached in every day or every hour.
- Rather than promoting conservation at high-cost times, or shifting of load from system peak periods, demand charges encourage customers to waste resources on the arbitrary tasks of flattening their personal maximum loads, even if those occur at low-cost times. For instance, in order to respond to demand charges effectively, customers will need to install equipment to monitor loads, interrupt discretionary load, and schedule deferrable loads. Moreover, lower energy charges will encourage increased electric use, some of which will likely fall in the peak period.

Q: What pricing signals do demand charges give to customers?

A: Not only are demand charges ineffective in shifting loads off high-cost hours, they may cause some customers to shift loads in ways that increase costs. Demand charges also distract customer efforts from reducing energy use to shifting around demand, perhaps onto peak hours.

Q: Should demand charges be eliminated entirely from rates?

A: Yes, or nearly so. When time-of-use energy charges are introduced, demand charges should be eliminated, and the revenues currently collected through demand charges instead collected through peak-period energy charges. In other words, all system and regional transmission, substation and feeder costs would be recovered through on-peak energy charges. This time-of-use rate design will encourage reduction of usage in high-load periods, when transmission and distribution equipment is heavily loaded.

Q: Is it feasible to design a TOU rate that signals the highest cost hours?

A: Yes. A three-period (peak, shoulder, and off-peak), seasonally differentiated rate, with a narrow "critical peak" period, for example, would provide a useful price signal.

Q: Has Manitoba Hydro acknowledged that TOU rates could effectively replace demand charges?

A: Yes.

> Manitoba Hydro recognizes that in the design of a Time-of-Use rate structure, for example, it may be reasonable to recover some portion of demand-related cost in a peak period energy charge. However, the extent to which that is appropriate depends upon the seasonality of the peak period and the extent to which other rate design factors require consideration. (GAC-MH I-14)

It is time to actually consider the rate-design factors and implement time-of-use rates.

E. Demand Ratchets

Q: What are demand ratchets?

A: Ratchets are rate provisions that charge demand-metered customers based on their maximum demand in current and previous months, not just on the maximum demand established in the month of the bill.

Q: How does Manitoba Hydro use demand ratchets in its rates?

A: Under this ratchet, the customer's monthly billing demand is the greatest of:

- The customer's maximum demand in that month;
- 25% of contract demand;
- 25% of the highest measured demand in the previous 12 months.

Q: Should demand ratchets be eliminated?

A: Yes. I recommend that ratchets be eliminated, for the following reasons:

- Ratchets worsen the adverse effects of demand charges. In the months when the customer's demand is below 25% of the annual maximum, demand charges are fixed and therefore, will provide no incentive to conserve at any time during the month.
- They excessively penalize the customer for a kWh increase in maximum annual billing demand. For example, consider a Medium General Service customer that experiences a much higher billing demand in December than in any other month. For each additional kVA (roughly a kWh) in that one December hour, this customer will pay December's demand charge of $10.54/kVA plus 25% of that demand charge for each of the next 11 months, or a total increase in annual payments of $39.50. This charge is nearly 1,000 times the tail block charge of 4.117¢/kWh charged in all other December hours.
- Ratchets provide confusing and misleading signals to customers,
- Ratchets reduce customers' control over their bills, and
- Ratchets result in disruptive bill impacts, especially for a customer who unintentionally establishes a new maximum demand.

Ratchets may serve a utility's desire for revenue stability, but they are antithetical to the goal of conservation, cost-based rate design, reduction of system and environmental costs, and non-disruptive impacts on customer bills.

VI. Cost-of-Service Study

Q: The Board directed Hydro to make several changes to its PCOSS18 methodology. Do you have any comments on Hydro's response?

A: I have not identified any problems with the Company's revisions to its cost-of-service study methodology to reflect the Board's Order 164-16. However, there are several pending issues not addressed in PCOSS18 that require data collection and further analysis. Order 164/16 gives the Company the responsibility of pursuing these issues but does not establish a time frame for that effort. I recommend that the Board direct the Company to develop data necessary to address deficiencies in the COSS methodology, including:

- Failure to reflect the load diversity among classes on distribution substations.
- A lack of data to support the sub-classification of distribution line and pole costs between primary and secondary service.
- The need for improving the service-drop allocator to reflect the sharing of service drops.

Q: Does this conclude your evidence?

A: Yes.

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

"Price Effects as a Benefit of Energy-Efficiency Programs" (with John Plunkett), *2014 ACEEE Summer Study on Energy Efficiency in Buildings* (5) 57–5-69. 2014.

"Environmental Regulation in the Changing Electric-Utility Industry" (with Rachel Brailove), *International Association for Energy Economics Seventeenth Annual North American Conference* (96–105). Cleveland, Ohio: USAEE. 1996.

"The Price is Right: Restructuring Gain from Market Valuation of Utility Generating Assets" (with Jonathan Wallach), *International Association for Energy Economics Seventeenth Annual North American Conference* (345–352). Cleveland, Ohio: USAEE. 1996.

"The Future of Utility Resource Planning: Delivering Energy Efficiency through Distributed Utilities" (with Jonathan Wallach), *International Association for Energy Economics Seventeenth Annual North American Conference* (460–469). Cleveland, Ohio: USAEE. 1996.

"The Future of Utility Resource Planning: Delivering Energy Efficiency through Distribution Utilities" (with Jonathan Wallach), *1996 Summer Study on Energy Efficiency in Buildings,* Washington: American Council for an Energy-Efficient Economy 7(7.47–7.55). 1996.

"The Allocation of DSM Costs to Rate Classes," *Proceedings of the Fifth National Conference on Integrated Resource Planning.* Washington: National Association of Regulatory Utility Commissioners. May 1994.

"Environmental Externalities: Highways and Byways" (with Bruce Biewald and William Steinhurst), *Proceedings of the Fifth National Conference on Integrated Resource Planning.* Washington: National Association of Regulatory Utility Commissioners. May 1994.

"The Transfer Loss is All Transfer, No Loss" (with Jonathan Wallach), The *Electricity Journal* 6:6 (July 1993).

"Benefit-Cost Ratios Ignore Interclass Equity" (with others), *DSM Quarterly*, Spring 1992.

"ESCos or Utility Programs: Which Are More Likely to Succeed?" (with Sabrina Birner), *The Electricity Journal* 5:2, March 1992.

"Determining the Marginal Value of Greenhouse Gas Emissions" (with Jill Schoenberg), *Energy Developments in the 1990s: Challenges Facing Global/Pacific Markets, Vol. II*, July 1991.

“Monetizing Environmental Externalities for Inclusion in Demand-Side Management Programs” (with Emily Caverhill), *Proceedings from the Demand-Side Management and the Global Environment Conference*, April 1991.

“Accounting for Externalities” (with Emily Caverhill). *Public Utilities Fortnightly* 127(5), March 1 1991.

“Methods of Valuing Environmental Externalities” (with Emily Caverhill), *The Electricity Journal* 4(2), March 1991.

“The Valuation of Environmental Externalities in Energy Conservation Planning” (with Emily Caverhill), *Energy Efficiency and the Environment: Forging the Link*. American Council for an Energy-Efficient Economy; Washington: 1991.

“The Valuation of Environmental Externalities in Utility Regulation” (with Emily Caverhill), *External Environmental Costs of Electric Power: Analysis and Internalization*. Springer-Verlag; Berlin: 1991.

“Analysis of Residential Fuel Switching as an Electric Conservation Option” (with Eric Espenhorst and Ian Goodman), *Gas Energy Review*, December 1990.

“Externalities and Your Electric Bill,” *The Electricity Journal*, October 1990, p. 64.

“Monetizing Externalities in Utility Regulations: The Role of Control Costs” (with Emily Caverhill) *Proceedings from the NARUC National Conference on Environmental Externalities*, October 1990.

“Monetizing Environmental Externalities in Utility Planning” (with Emily Caverhill), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

“Analysis of Residential Fuel Switching as an Electric Conservation Option” (with Eric Espenhorst and Ian Goodman), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

“A Utility Planner’s Checklist for Least-Cost Efficiency Investment” (with John Plunkett) in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

Environmental Costs of Electricity (with Richard Ottinger et al.). Oceana; Dobbs Ferry, New York: September 1990.

“Demand-Side Bidding: A Viable Least-Cost Resource Strategy” (with John Plunkett and Jonathan Wallach), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

“Incorporating Environmental Externalities in Evaluation of District Heating Options” (with Emily Caverhill), *Proceedings from the International District Heating and Cooling Association 81st Annual Conference*, June 1990.

“A Utility Planner’s Checklist for Least-Cost Efficiency Investment,” (with John Plunkett), *Proceedings from the Canadian Electrical Association Demand-Side Management Conference*, June 1990.

"Incorporating Environmental Externalities in Utility Planning" (with Emily Caverhill), *Canadian Electrical Association Demand Side Management Conference*, May 1990.

"Is Least-Cost Planning for Gas Utilities the Same as Least-Cost Planning for Electric Utilities?" in *Proceedings of the NARUC Second Annual Conference on Least-Cost Planning*, September 10–13 1989.

"Conservation and Cost-Benefit Issues Involved in Least-Cost Planning for Gas Utilities," in *Least Cost Planning and Gas Utilities: Balancing Theories with Realities*, Seminar proceedings from the District of Columbia Natural Gas Seminar, May 23 1989.

"The Role of Revenue Losses in Evaluating Demand-Side Resources: An Economic Re-Appraisal" (with John Plunkett), *Summer Study on Energy Efficiency in Buildings, 1988*, American Council for an Energy Efficient Economy, 1988.

"Quantifying the Economic Benefits of Risk Reduction: Solar Energy Supply Versus Fossil Fuels," in *Proceedings of the 1988 Annual Meeting of the American Solar Energy Society*, American Solar Energy Society, Inc., 1988, pp. 553–557.

"Capital Minimization: Salvation or Suicide?," in I. C. Bupp, ed., *The New Electric Power Business*, Cambridge Energy Research Associates, 1987, pp. 63–72.

"The Relevance of Regulatory Review of Utility Planning Prudence in Major Power Supply Decisions," in *Current Issues Challenging the Regulatory Process*, Center for Public Utilities, Albuquerque, New Mexico, April 1987, pp. 36–42.

"Power Plant Phase-In Methodologies: Alternatives to Rate Shock," in *Proceedings of the Fifth NARUC Biennial Regulatory Information Conference*, National Regulatory Research Institute, Columbus, Ohio, September 1986, pp. 547–562.

"Assessing Conservation Program Cost-Effectiveness: Participants, Non-participants, and the Utility System" (with A. Bachman), *Proceedings of the Fifth NARUC Biennial Regulatory Information Conference*, National Regulatory Research Institute, Columbus, Ohio, September 1986, pp. 2093–2110.

"Forensic Economics and Statistics: An Introduction to the Current State of the Art" (with Eden, P., Fairley, W., Aller, C., Vencill, C., and Meyer, M.), *The Practical Lawyer*, June 1 1985, pp. 25–36.

"Power Plant Performance Standards: Some Introductory Principles," *Public Utilities Fortnightly*, April 18 1985, pp. 29–33.

"Opening the Utility Market to Conservation: A Competitive Approach," *Energy Industries in Transition, 1985–2000*, Proceedings of the Sixth Annual North American Meeting of the International Association of Energy Economists, San Francisco, California, November 1984, pp. 1133–1145.

"Insurance Market Assessment of Technological Risks" (with Meyer, M., and Fairley, W) *Risk Analysis in the Private Sector*, pp. 401–416, Plenum Press, New York 1985.

"Revenue Stability Target Ratemaking," *Public Utilities Fortnightly*, February 17 1983, pp. 35–39.

"Capacity/Energy Classifications and Allocations for Generation and Transmission Plant" (with M. Meyer), *Award Papers in Public Utility Economics and Regulation*, Institute for Public Utilities, Michigan State University 1982.

Design, Costs and Acceptability of an Electric Utility Self-Insurance Pool for Assuring the Adequacy of Funds for Nuclear Power Plant Decommissioning Expense, (with Fairley, W., Meyer, M., and Scharff, L.) (NUREG/CR-2370), U.S. Nuclear Regulatory Commission, December 1981.

Optimal Pricing for Peak Loads and Joint Production: Theory and Applications to Diverse Conditions (Report 77-1), Technology and Policy Program, Massachusetts Institute of Technology, September 1977.

REPORTS

"Review of the NS Power Application for Approval of its 2017 Annually Adjusted Rates and Load Following Setting Methodology" (with Stacia Harper). August 2017. Filed by the Nova Scotia Consumer Advocate in N.S. UARB Matter No. M08114.

"Charge Without a Cause? Assessing Electric Utility Demand Charges on Small Consumers" (with John T. Colgan, Rick Gilliam, Douglas Jester and Mark LeBel). Electricity Rate Design Review No. 1, July 2016.

"Implications of the Proposed Clean Power Plan for Arkansas: Review of Stakeholder Concerns and Assessment of Feasibility." 2014. Report to Arkansas Audubon, Arkansas Public Policy Panel, and Arkansas Sierra Club.

"Comments on Nova Scotia Power Inc.'s Proposed Capital Expenditure Justification Criteria." 2013. Filed by the Nova Scotia Consumer Advocate in N.S. UARB Matter No. 05355.

"Avoided Energy Supply Costs in New England: 2013 Report" (with Rick Hornby, David White, John Rosenkranz, Ron Denhardt, Elizabeth Stanton, Jason Gifford, Bob Grace, Max Chang, Patrick Luckow, Thomas Vitolo, Patrick Knight, Ben Griffiths, and Bruce Biewald). 2011. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid Company.

"Affordability of Pollution Control on the Apache Coal Units: Review of Arizona Electric Power Cooperative's Comments on Behalf of the Sierra Club" (with Ben Griffiths). 2012. Filed as part of comments in Docket EPA-R09-OAR-2012-0021 by National Parks Conservation Association, Sierra Club, et al.

"Audubon Arkansas Comments on Entergy's 2012 IRP." 2012. Prepared for and filed by Audubon Arkansas in Arkansas PUC Docket No. 07-016-U.

“Economic Benefits from Early Retirement of Reid Gardner” (with Jonathan Wallach). 2012. Prepared for and filed by the Sierra Club in PUC of Nevada Docket No. 11-08019.

“Analysis of Via Verde Need and Economics.” 2012. Appendix V-4 of public comments of the Sierra Club et al. in response to November 30 2011 draft of U.S. Army Corps of Engineers environmental assessment in Department of the Army Environmental Assessment and Statement of Finding for Permit Application SAJ-2010-02881.

“Comments for The Alliance for Affordable Energy on Staff’s ‘Proposed Integrated Resource Planning Rules for Electric Utilities in Louisiana.’” 2011. Filed by the Alliance for Affordable Energy in Louisiana PSC Docket R-30021.

“Avoided Energy Supply Costs in New England: 2011 Report” (with Rick Hornby, Carl Swanson, David White, Jason Gifford, Max Chang, Nicole Hughes, Matthew Wittenstein, Rachel Wilson, and Bruce Biewald). 2011. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid Company.

“State of Ohio Energy-Efficiency Technical-Reference Manual Including Predetermined Savings Values and Protocols for Determining Energy and Demand Savings” (with others). 2010. Burlington, Vt.: Vermont Energy Investment Corporation.

“Avoided Energy Supply Costs in New England: 2011 Report” (with Rick Hornby, Carl Swanson, David White, Ian Goodman, Bob Grace, Bruce Biewald, Ben Warfield, Jason Gifford, and Max Chang). 2009. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid Company.

“Green Resource Portfolios: Development, Integration, and Evaluation” (with Jonathan Wallach and Richard Mazzini). 2008. Report to the Green Energy Coalition presented as evidence in Ont. Energy Board EB 2007-0707.

“Risk Analysis of Procurement Strategies for Residential Standard Offer Service” (with Jonathan Wallach, David White, and Rick Hornby) report to Maryland Office of People’s Counsel. 2008. Baltimore: Maryland Office of People’s Counsel.

“Avoided Energy Supply Costs in New England: 2007 Final Report” (with Rick Hornby, Carl Swanson, Michael Drunsic, David White, Bruce Biewald, and Jenifer Callay). 2007. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid Company.

“Integrated Portfolio Management in a Restructured Supply Market” (with Jonathan Wallach, William Steinhurst, Tim Woolf, Anna Sommers, and Kenji Takahashi). 2006. Columbus, Ohio: Office of the Ohio Consumers’ Counsel.

“Natural Gas Efficiency Resource Development Potential in New York” (with Phillip Mosenthal, R. Neal Elliott, Dan York, Chris Neme, and Kevin Petak). 2006. Albany, N.Y.; New York State Energy Research and Development Authority.

“Natural Gas Efficiency Resource Development Potential in Con Edison Service Territory” (with Phillip Mosenthal, Jonathan Kleinman, R. Neal Elliott, Dan York, Chris Neme, and

Kevin Petak. 2006. Albany, N.Y.; New York State Energy Research and Development Authority.

"Evaluation and Cost Effectiveness" (principal author), Ch. 14 of "California Evaluation Framework" Prepared for California utilities as required by the California Public Utilities Commission. 2004.

"Energy Plan for the City of New York" (with Jonathan Wallach, Susan Geller, Brian Tracey, Adam Auster, and Peter Lanzalotta). 2003. New York: New York City Economic Development Corporation.

"Updated Avoided Energy Supply Costs for Demand-Side Screening in New England" (with Susan Geller, Bruce Biewald, and David White). 2001. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o New England Power Supply Company.

"Review and Critique of the Western Division Load-Pocket Study of Orange and Rockland Utilities, Inc." (with John Plunkett, Philip Mosenthal, Robert Wichert, and Robert Rose). 1999. White Plains, N.Y.: Pace University School of Law Center for Environmental Studies.

"Avoided Energy Supply Costs for Demand-Side Management in Massachusetts" (with Rachel Brailove, Susan Geller, Bruce Biewald, and David White). 1999. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o New England Power Supply Company.

"Performance-based Regulation in a Restructured Utility Industry" (with Bruce Biewald, Tim Woolf, Peter Bradford, Susan Geller, and Jerrold Oppenheim). 1997. Washington: NARUC.

"Distributed Integrated-Resource-Planning Guidelines." 1997. Appendix 4 of "The Power to Save: A Plan to Transform Vermont's Energy-Efficiency Markets," submitted to the Vt. PSB in Docket No. 5854. Montpelier: Vermont DPS.

"Restructuring the Electric Utilities of Maryland: Protecting and Advancing Consumer Interests" (with Jonathan Wallach, Susan Geller, John Plunkett, Roger Colton, Peter Bradford, Bruce Biewald, and David Wise). 1997. Baltimore, Maryland: Maryland Office of People's Counsel.

"Comments of the New Hampshire Office of Consumer Advocate on Restructuring New Hampshire's Electric-Utility Industry" (with Bruce Biewald and Jonathan Wallach). 1996. Concord, N.H.: NH OCA.

"Estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities" (with Susan Geller, Rachel Brailove, Jonathan Wallach, and Adam Auster). 1996. On behalf of the Massachusetts Attorney General (Boston).

From Here to Efficiency: Securing Demand-Management Resources (with Emily Caverhill, James Peters, John Plunkett, and Jonathan Wallach). 1993. 5 vols. Harrisburg, Penn: Pennsylvania Energy Office.

"Analysis Findings, Conclusions, and Recommendations," vol. 1 of "Correcting the Imbalance of Power: Report on Integrated Resource Planning for Ontario Hydro" (with Plunkett, John, and Jonathan Wallach), December 1992.

"Estimation of the Costs Avoided by Potential Demand-Management Activities of Ontario Hydro," December 1992.

"Review of the Elizabethtown Gas Company's 1992 DSM Plan and the Demand-Side Management Rules" (with Jonathan Wallach, John Plunkett, James Peters, Susan Geller, Blair. Hamilton, and Andrew Shapiro). 1992. Report to the New Jersey Department of Public Advocate.

Environmental Externalities Valuation and Ontario Hydro's Resource Planning (with E. Caverhill and R. Brailove), 3 vols.; prepared for the Coalition of Environmental Groups for a Sustainable Energy Future, October 1992.

"Review of Jersey Central Power & Light's 1992 DSM Plan and the Demand-Side Management Rules" (with Jonathan Wallach et al.); Report to the New Jersey Department of Public Advocate, June 1992.

"The AGREA Project Critique of Externality Valuation: A Brief Rebuttal," March 1992.

"The Potential Economic Benefits of Regulatory NO_X Valuation for Clean Air Act Ozone Compliance in Massachusetts," March 1992.

"Initial Review of Ontario Hydro's Demand-Supply Plan Update" (with David Argue et al.), February 1992.

"Report on the Adequacy of Ontario Hydro's Estimates of Externality Costs Associated with Electricity Exports" (with Emily Caverhill), January 1991.

"Comments on the 1991–1992 Annual and Long Range Demand-Side-Management Plans of the Major Electric Utilities," (with John Plunkett et al.), September 1990. Filed in NY PSC Case No. 28223 in re New York utilities' DSM plans.

"Power by Efficiency: An Assessment of Improving Electrical Efficiency to Meet Jamaica's Power Needs," (with Conservation Law Foundation, et al.), June 1990.

"Analysis of Fuel Substitution as an Electric Conservation Option," (with Ian Goodman and Eric Espenhorst), Boston Gas Company, December 22 1989.

"The Development of Consistent Estimates of Avoided Costs for Boston Gas Company, Boston Edison Company, and Massachusetts Electric Company" (with Eric Espenhorst), Boston Gas Company, December 22 1989.

"The Valuation of Externalities from Energy Production, Delivery, and Use: Fall 1989 Update" (with Emily Caverhill), Boston Gas Company, December 22 1989.

"Conservation Potential in the State of Minnesota," (with Ian Goodman) Minnesota Department of Public Service, June 16 1988.

"Review of NEPOOL Performance Incentive Program," Massachusetts Energy Facilities Siting Council, April 12 1988.

"Application of the DPU's Used-and-Useful Standard to Pilgrim 1" (With C. Wills and M. Meyer), Massachusetts Executive Office of Energy Resources, October 1987.

"Constructing a Supply Curve for Conservation: An Initial Examination of Issues and Methods," Massachusetts Energy Facilities Siting Council, June 1985.

"Final Report: Rate Design Analysis," Pacific Northwest Electric Power and Conservation Planning Council, December 18 1981.

PRESENTATIONS

"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.

"Adding Transmission into New York City: Needs, Benefits, and Obstacles." Presentation to FERC and the New York ISO on behalf of the City of New York. October 2004.

"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.

"Distributed Utility Planning." With Steve Litkovitz. Presentation to the Vermont Distributed-Utility-Planning Collaborative. November 1999.

"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.

"Cost Allocation for Utility Ratemaking." With Susan Geller. Day-long workshop for the staff of the Connecticut Department of Public Utility Control, October 1993.

"Comparing and Integrating DSM with Supply." Day-long presentation as part of the Demand-Side-Management Training Institute's workshop, "DSM for Public Interest Groups," October 1993.

"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.

"Cost-Effectiveness Analysis." 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.

"Environmental Externalities: Current Approaches and Potential Implications for District Heating and Cooling" (with R. Brailove), International District Heating and Cooling Association 84th Annual Conference. June 1993.

"Using the Costs of Required Controls to Incorporate the Costs of Environmental Externalities in Non-Environmental Decision-Making." Presentation at the American Planning Association 1992 National Planning Conference; presentation cosponsored by the Edison Electric Institute. May 1992.

"Cost Recovery and Decoupling" and "The Clean Air Act and Externalities in Utility Resource Planning" panels (session leader), DSM Advocacy Workshop. April 15 1992.

"Overview of Integrated Resources Planning Procedures in South Carolina and Critique of South Carolina Demand Side Management Programs," Energy Planning Workshops; Columbia, S.C. October 21 1991.

"Least Cost Planning and Gas Utilities." Demand-Side Management and the Global Environment Conference; Washington, D.C. April 22 1991.

Conservation Law Foundation Utility Energy Efficiency Advocacy Workshop; Boston, February 28 1991.

"Least-Cost Planning in a Multi-Fuel Context." NARUC Forum on Gas Integrated Resource Planning; Washington, D.C., February 24 1991.

"Accounting for Externalities: Why, Which and How?" Understanding Massachusetts' New Integrated Resource Management Rules. Needham, Massachusetts, November 9 1990.

New England Gas Association Gas Utility Managers' Conference. Woodstock, Vermont, September 10 1990.

"Quantifying and Valuing Environmental Externalities." Presentation at the Lawrence Berkeley Laboratory Training Program for Regulatory Staff, sponsored by the U.S. Department of Energy's Least-Cost Utility Planning Program; Berkeley, California, February 2 1990;

"Conservation in the Future of Natural Gas Local Distribution Companies." District of Columbia Natural Gas Seminar; Washington, D.C. May 23 1989.

"Conservation and Load Management for Natural Gas Utilities," Massachusetts Natural Gas Council; Newton, Massachusetts. April 3 1989.

New England Conference of Public Utilities Commissioners, Environmental Externalities Workshop. Portsmouth, New Hampshire, January 22–23 1989.

"Assessment and Valuation of External Environmental Damages." New England Utility Rate Forum. Plymouth, Massachusetts, October 11 1985; "Lessons from Massachusetts on Long Term Rates for QFs".

"Reviewing Utility Supply Plans." Massachusetts Energy Facilities Siting Council; Boston, Massachusetts. May 30 1985.

"Power Plant Performance.," National Association of State Utility Consumer Advocates; Williamstown, Massachusetts. August 13 1984.

"Utility Rate Shock," National Conference of State Legislatures; Boston, Massachusetts, August 6 1984.

"Review and Modification of Regulatory and Rate Making Policy," National Governors' Association Working Group on Nuclear Power Cost Overruns; Washington, D.C., June 20 1984.

"Review and Modification of Regulatory and Rate Making Policy," Annual Meeting of the American Association for the Advancement of Science, Session on Monitoring for Risk Management; Detroit, Michigan, May 27 1983.

ADVISORY ASSIGNMENTS TO REGULATORY COMMISSIONS

District of Columbia Public Service Commission, Docket No. 834, Phase II; Least-cost planning procedures and goals. August 1987 to March 1988.

Connecticut Department of Public Utility Control, Docket No. 87-07-01, Phase 2; Rate design and cost allocations. March 1988 to June 1989.

Austin City Council, Austin Energy Rates, March to June 2012.

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 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 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 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 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 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 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 1979.

   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 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 1980.

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

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

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

13. **Texas** **PUC** 3298, Gulf States Utilities rates; East Texas Legal Services. August 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 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 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 1981 and February 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 1981.

    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 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. **DC** PSC FC785, Potomac Electric Power rate case; DC Peoples Counsel. July 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 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 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 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 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 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 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 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 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 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 1985 and October 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 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 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 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 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 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 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 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 1986.

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 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 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 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 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 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 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 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 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 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 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 1988.

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

68. **Mass. DPU** 88-123, petition of Riverside Steam & Electric; Riverside Steam and Electric Company. May 1988 and November 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 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 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 1988, supplemented August 1988; Losses and Expenses, September 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 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 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 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 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 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 rates; Massachusetts Energy Office. June 1989.

    Prudence of decision to spend $400 million from 1986–88 to return Pilgrim nuclear 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 1989. Rebuttal, October 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 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 1989. Surrebuttal February 1990.

Analysis of a proposed 20-year power purchase. Comparison to efficiency investment. Critique of conservation potential analysis. Analysis of Vermont electric energy supply. Planning risk of large supply additions. Valuation of environmental externalities. Identification of possible improvements to proposed contract.

81. **Mass.** **DPU** 89-239, inclusion of externalities in energy-supply planning, acquisition, and dispatch for Massachusetts utilities. Boston Gas Company. 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 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 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 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 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 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 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 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, commission investigation; Southern Environmental Law Center. March 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 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 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 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 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 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 1991.

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

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

    Obligation to pursue integrated resource planning, 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 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 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 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 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 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 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 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 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 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 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 1993; rebuttal February 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 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 incentive mechanisms in rates for the Consumers Gas Company.

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.

241. **Conn. Siting Council** 370A, Connecticut Light & Power transmission projects; Connecticut Office of Consumer Counsel. July 2009. Also filed and presented in **MA EFSB** 08-02, February 2010.

Need for transmission projects. Modeling of transmission system. Realistic modeling of operator responses to contingencies

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

Revenue-decoupling mechanism. Automatic rate adjustments.

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

Cost-of-service study. Cost allocators for generation, transmission, and substation.

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

Automatic cost-adjustment mechanisms. Net power costs and related risks. Effects of energy-cost-adjustment mechanisms on utility performance.

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.

253. **Md. PSC** 9230, Baltimore Gas & Electric rates; Maryland Office of People's Counsel. Direct, July 2010; rebuttal, surrebuttal, August 2010.

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.

Cost allocation. Cost of capital. Effect on rates of growth in sales.

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 M03632, 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.

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

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.

Revenue requirements. Allocation of tax benefits. Ratemaking.

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.

Estimating gas pipeline and distribution costs avoidable through gas DSM and curtailment of electric generation. Integrating DSM and pipeline planning.

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.

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

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.

Redesigning residential rates to simplify tier structure while maintaining efficiency and conservation incentives. Effect of marginal price on energy consumption. Realistic modeling of consumer price response. Benefits of minimizing customer charges.

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-3867-2013 phase 1, Gaz Métro cost allocation and rate structure; ROEÉ. 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-3867-2013 phase 3A; Gaz Métro estimates of marginal O&M costs; ROEÉ. 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.

321. **Mass. DPU** 17-05, Eversource Rate Case, Cape Light Compact. Direct April 2017, Rebuttal May 2017.

Critique of proposed performance-based ratemaking mechanism. Proposal for improvements.

322. **PUCO** 16-1852, AEP Ohio Electric Security Plan, Natural Resources Defense Council. May 2017.

Residential customer charge. Cost causation. Effect of rate design on consumption.

323. **Iowa Utilities Board** RPU-2017-0001, Interstate Power and Light rate case, Natural Resources Defense Council. Direct August 2017, Reply September 2017.

Critique of proposed demand-charge pilot rates for residential and small commercial customers. Defects of demand rates and shortcomings of IPL experimental proposal design.

324. **N.S. UARB** Matter No. M08087, NS Power 2017 Load Forecast, Nova Scotia Consumer Advocate. Direct August 2017.

Review of forecast methodology, including extrapolation of drivers of commercial load from US national data; treatment of non-firm and competitive loads; behind-the-meter generation and controlling peak-load growth.

325. **Québec Régie de l'énergie** R-3867-2013 phase 3B; Gaz Métro line-extension policy; ROEÉ. September 2017.

The costs of adding new load. Estimating the durability of revenues from line extensions.

326. **Mass. EFSB** 17-02; Eversource proposed Hudson-Sudbury transmission line; Town of Sudbury. October 2017.

Accuracy of ISO-NE regional load forecasts. Potential for distributed solar, storage and demand response.

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
ROEÉ	Regroupement des organismes environnementaux en énergie
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