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31 August 2010

Ms. Kirsten Walli, Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON
M4P 1E4

Dear Ms Walli:

Re: EB-2010-0008 – OPG Payments – Evidence filed by GEC

Attached please find the evidence of Mr. Paul Chernick in regard to issues 2.2 and 3.3 which is being filed by GEC in this matter.

Two hard copies will be delivered to the Board.

Sincerely,

David Poch

1649 Old Brooke Road, Maberly, Ontario K0H 2B0 e-mail: dpoch@eelaw.ca

PROVINCE OF ONTARIO

BEFORE THE ONTARIO ENERGY BOARD

Ontario Power Generation Inc.	**)**	
2011–2012 Payment Amounts for	**)**	**EB-2010-0008**
Prescribed Facilities	**)**	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF THE

GREEN ENERGY COALITION

Resource Insight, Inc.

AUGUST 31, 2010

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I. Identification & 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 St., 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, 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 (PBR) and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified over two hundred times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in Ontario, Alberta, Manitoba, Nova Scotia, British Columbia and thirty states, as well as the two US Federal agencies.

Q: Have you previously presented evidence before the Ontario Energy Board?

A: Yes. I filed evidence and/or testified before the Ontario Environmental Assessment Board in Ontario Hydro's Demand/Supply Plan hearings in 1992, and before the OEB in the following dockets:

- EBRO 490, DSM cost recovery and lost-revenue adjustment mechanism for Consumers Gas Company.
- EBRO 495, LRAM and shared-savings incentive for DSM performance of Consumers Gas.
- RP-1999-0034, Ontario Performance-Based Rates for electric distribution utilities.
- RP-1999-0044, Ontario Hydro transmission-cost allocation and rate design.
- RP-1999-0017, Union Gas proposal for performance-based rates.
- RP-2002-0120, Ontario transmission-system code.
- RP-2004-0188, cost recovery and DSM for electric-distribution utilities
- EB-2005-0520, rate design and cost allocation for Union Gas firm customers.
- EB-2006-0021, gas utility DSM planning and cost recovery.

- EB-2007-0707, review of Ontario Power Authority's Integrated Power System Plan.
- EB-2007-0905; Ontario Power Generation rate proceeding for prescribed facilities.

In addition, I have assisted my clients in preparation of comments in various proceedings, including the distributed generation consultation (EB-2007-0630), the electric distribution rate design proceeding (EB-2007-0031) and the distribution-utility decoupling case (EB-2010-0060).

II. Introduction

Q: On whose behalf are you testifying?

A: My testimony is sponsored by the Green Energy Coalition.

Q: What is the purpose of your testimony?

A: My clients have asked me to review the policy implications of two matters: Ontario Power Generation's (OPG) request for a cash return on construction work in progress (CWIP) for the Darlington Refurbishment project and OPG's proposal to continue using a single blended cost of capital for its two very different regulated operating segments: nuclear and hydroelectric operations.[1]

Q: What do you conclude regarding a return on CWIP?

A: The inclusion of a cash return on CWIP forces customers to pay for projects that are not providing any benefits. In many cases, the customers who pay the CWIP return will never have their investment returned. CWIP reduces intergenerational

[1] The cash return on CWIP is often referred to as "CWIP in rate base" or simply CWIP.

equity and can reduce the incentive for a utility to exercise cost control and avoid delays.

A return on CWIP is justified only in exceptional circumstances, such as to preserve the financial integrity of the utility or to encourage reluctant transmission and distribution utilities to facilitate generation projects sponsored by other parties and required by public policy. Those exceptional circumstances do not exist in this case.

The Company has not considered how a return of CWIP on the Darlington Refurbishment would interact with other increases in its own charges or in other charges paid by Ontario electricity consumers. Those customers are facing many other cost increases during the Darlington Refurbishment construction period, including transmission investments, new renewable and clean-power contracts, the Bruce A restart and refurbishment contracts, and the loss of energy supplies from the coal plants and the Darlington units taken off-line early for refurbishment. Adding early cost-recovery on CWIP in the same period will likely make a bad situation worse.

Q: What do you conclude regarding the use of different costs of capital for OPG's nuclear and hydro-electric segments?

A: It is clear that refurbishing and operating nuclear plants is riskier than building and operating hydro-electric plants. Using the same cost of capital for both segments of OPG's benefits overstates the costs of hydro-electric projects and understates that of nuclear projects. The choice of the cost of capital may be critical in decisions regarding the Darlington Refurbishment and other projects.

III. Construction Work in Progress

Q: Why is a current return on CWIP generally inappropriate?

A: Charging current customers for CWIP unfairly forces them to pay for investments that are not yet used or useful, transfers risk from the utility to consumers, and reduces the pressure for the utility to maintain financial discipline.

Q: What rationale does OPG advance for being allowed to charge current customers for a cash return on CWIP for the Darlington Refurbishment project?

A: As presented in Exhibit D2-2-1 and the evidence of Ralph L. Luciani (Exhibit D4-1-1), OPG's arguments focus on precedent, incentives, maintaining OPG's financial integrity, and benefits to customers.

A. Precedent and Incentives

Q: What Ontario precedents does OPG cite in support of its request for a cash return on CWIP for the Darlington Refurbishment?

A: Mr. Luciani cites the Board's approval of a current return for CWIP on the Niagara Reinforcement in EB-2006-0501. OPG itself cites "The Regulatory Treatment of Infrastructure Investment in connection with Rate-regulated Activities of Distributors and Transmitters in Ontario" (Board Report, EB-2009-0152, January 15, 2010).

Q: How does Hydro One's situation with respect to the Niagara Reinforcement project compare to OPG's situation with respect to the Darlington Refurbishment project?

A: In EB-2006-0501, the OEB allowed Hydro One to expense and charge a return on CWIP for the Niagara Reinforcement project (Decision with Reasons, August 16, 2007, pp. 61–64). Hydro One had asked the Board to allow both a return on

CWIP and amortization of capitalized expenditure on the Niagara Reinforcement, due to uncertainty in the project's future. The Board rejected the amortization of the costs, but allowed recovery of CWIP, based on the uncertainty that the project would ever enter service.

> The Board agrees that special regulatory treatment is appropriate for the NRP because a recognizable risk has materialized out of the land claim dispute in Caledonia, the resolution of which is beyond the control of Hydro One. (EB-2006-0501, p. 63)
>
> It is not known if the project will eventually be completed, if it will come into service with a different route and additional costs, or if it must be abandoned and written off. (p. 64)
>
> …the Board has decided to allow Hydro One to expense—rather than capitalize—the AFUDC, or carrying costs, associated with the project based on the actual expenditures made to date….with no explicit time limit as it remains uncertain when the Caledonia dispute will be resolved. (p. 64)

Q: Has a problem similar to the land claim dispute in Caledonia arisen for the Darlington Refurbishment?

A: No. OPG has not indicated any doubt about the eventual completion of the refurbishment and the commercial operation of the refurbished units. While there is of course uncertainty (especially in that no direction to proceed beyond the definition phase has been received), no particular obstacle has arisen thus far. If that changes, and the Darlington Refurbishment is suspended, OPG might seek a return under CWIP under the Niagara Reinforcement precedent.

Q: Did Hydro One request a return on CWIP for projects other than the Niagara Reinforcement project?

A: Yes. In EB-2006-0501, Hydro One requested CWIP for three other projects that it considered to be driven by supply-mix considerations: the Bruce transmission reinforcement, the Quebec Intertie, and static VAR compensators in south-western Ontario. Hydro One estimates the cost if these three projects at about

$181 million, or almost 3% of transmission rate base by the end of the rate period in 2008, with more costs to come. OPG now expects the Bruce transmission project to cost $696 million over seven years, reaching 7.6% of transmission rate base by 2012 (EB-2010-0002, Exhibit D1-3-3, Appendix A, Table 2; Exhibit D2-1-1).[2]

The Board rejected requests for a return on CWIP for these projects in EB-2006-0501 and Hydro One does not appear to have requested CWIP for them since. The cost estimate for the Bruce transmission project has increased in each rate case since 2005, and its schedule has slipped. The Board has not viewed the Bruce uncertainties as being comparable to that of the Niagara Reinforcement project, which is suspended and may never enter service.

Q: Did the Board explain why it allowed a return on CWIP for the Niagara Reinforcement project, with its uncertain status, but not the other projects?

A: The Board (EB-2006-0501, p. 60) summarized the arguments against Hydro One's proposal as follows:

> - There is no reason why Hydro One should be compensated now for risks that may not materialize.
> - The proposal is a significant departure from conventional regulatory treatment for capital projects. The Board should permit departures only under very exceptional circumstances and Hydro One has failed to establish that such exceptional circumstances exist. To allow Hydro One the relief it is seeking would set a precedent that may prompt other Ontario utilities to seek similar relief. Before setting such a precedent, the Board must be satisfied that conventional regulatory treatment is inadequate to meet needs such as those associated with the designated projects.
> - If construction is delayed or if there are abandonment issues, Hydro One would be free to come to the Board for relief.

[2] Hydro One also has distribution operations with assets about 70% of its transmission assets.

- Hydro One has not established that it is now subject to an increased risk with respect to the recovery of the costs associated with these projects.

- Hydro One has not established the need for "incentives" to undertake or complete those projects.

- FERC precedents arise out of a different regulatory regime and are not applicable in the Ontario context.

- The benefits to ratepayers as articulated by Hydro One have been overstated.

The Board stated (p. 60) it "shares these concerns and finds that a departure from conventional regulatory treatment has not been justified." Other than finding precedents from the U.S. Federal Energy Regulatory Commission and other jurisdictions unpersuasive, the Board highlighted the following issues (EB-2006-0501, p. 61):

> The cost of the designated projects, while large in absolute terms, is not particularly significant in relation to Hydro One's rate base, and there is no evidence that Hydro One will have difficulty financing the projects under conventional regulatory treatment.
>
> The Board is not persuaded that ratepayers would benefit from the proposed special regulatory treatment. Specifically, the Board does not accept Hydro One's argument that the treatment would result in revenue neutrality and rate smoothing.
>
> …the Board is not convinced that Hydro One will be unable to finance the capital program under the conventional approach.
>
> …the mitigation of losses that have not, and might not, occur is unnecessary and not appropriate. There is nothing in the record that would justify the burdening of ratepayers with such losses. In addition, Hydro One is reminded that it can come forward with applications for relief, if a special circumstance arises which puts it clearly at risk. The Board has promptly responded to such requests from other applicants in the past. There is no reason to expect that the Board would not deal fairly and promptly with Hydro One on these projects should significant issues arise in the future.

Q: Please summarize your understanding of the precedent in EB-2006-0501.

A: The Board essentially limited recovery of CWIP to projects that the utility would have difficulty financing under conventional regulatory treatment or (as in the case of the Niagara Reinforcement) when continued construction is in doubt.

Q: What relevance does OPG suggest the EB-2009-0152 Report has for this proceeding?

A: The Company asserts that the Report concludes that "inclusion of CWIP in rate base is consistent with the…objective [to]…foster timely investment by utilities in required infrastructure" (Exhibit D2-2-2, p. 2). OPG also claims, "Inclusion of CWIP in rate base for the Darlington Refurbishment project is warranted since it meets the criteria for qualifying investments specified by the OEB in its Report…. [T]he risks of the project are similar to those noted by the OEB for green energy projects, which include risks related to project delays, public controversy, and the recovery of costs" (Exhibit D2-2-2, p. 3).

Q: In what context does the EB-2009-0152 Report consider allowing a return on CWIP?

A: The Report indicates that the OEB will, on a case-by-case basis, consider applications by transmission and distribution utilities to include CWIP for projects related to the Green Energy Act.

> The Board acknowledges that, with the advent of the Green Energy and Green Economy Act, 2009 (the "Green Energy Act"), it is anticipated that electricity distributors and transmitters will undertake significant new infrastructure investment, particularly to accommodate new renewable generation. Accordingly, the Board recognizes the need for a regulatory framework that provides further flexibility which utilities may need, in appropriate circumstances, to make these infrastructure investments.
>
> Alternative mechanisms should be available in appropriate cases in relation to investments driven by the Green Energy Act and potentially in appropriate circumstances in relation to other types of investments.

> The Board emphasizes that conventional mechanisms continue to be appropriate and should therefore remain the core component of the Board's regulatory treatment of infrastructure investment. (Report, pp. i-ii)
>
> The Board recognizes that the Green Energy Act will increase the need for capital investment by distributors and transmitters. That investment is incremental to the more routine or traditional investments aimed at maintaining adequate levels of service and reliability, deploying smart meters and accommodating load growth. The Board also acknowledges that Green Energy Act-related investments may increase the risks that rate-regulated entities encounter. These risks, noted by stakeholders, include those related to project delays, landowner issues, public controversy, siting uncertainties, the recovery of costs, and the cancellation of the renewable generation projects that were to be served by the new investment. (Report, p. 12)
>
> It is anticipated that the Green Energy Act will increase the magnitude and complexity of infrastructure investment by distributors and transmitters. The availability of the alternative mechanisms provides the Board with a broad range of cost recovery mechanisms it can use, in appropriate circumstances, to enable distributors and transmitters, to raise capital on reasonable terms.
>
> The Board is of the view therefore that alternative mechanisms should be available in appropriate cases in relation to Green Energy Act–related investments. Alternative mechanisms can serve to address the unique risks that may arise with respect to those investments. Such mechanisms can also facilitate the timely development of the needed infrastructure, without the Board being required to mandate those investments. (Report, p. 13)

Q: How is the situation on which the Board focused in the EB-2009-0152 Report distinct from OPG's request for CWIP?

A: The primary issue in EB-2009-0152 was the role of utilities in constructing facilities to facilitate the interconnection of renewable generation developed by other parties (private developers, possibly OPG) under mandates that other entities (such as the Ontario Power Authority) are responsible for implementing. The development of renewable energy may be delayed by a lack of enthusiasm on the part of transmission and distribution utilities, regardless of the zeal of the parties directly involved in renewable development. The primary responsibility of the distribution and transmission utilities is the provision of reliable delivery services to consumers, not promoting renewable energy.[3]

In addition, the transmission-and-distribution utilities face the risk that the generation project for which they are building interconnection facilities will be delayed or cancelled due to (among other factors) "landowner issues, public controversy, [and] siting uncertainties," exposing the utility to uncertainty in recovering costs from the renewable energy project.[4] These risks are not subject to control by the utility, which would generally not even be a party to the siting, permitting, land procurement, design, construction, or financing of the power plant. As a result, utility management may be reluctant to commit resources to building facilities that may never be useful and for which cost recovery is uncertain.

Similarly, OPG's claim that "the risks of the project are similar to those noted by the OEB for green energy projects, which include risks related to project delays, public controversy, and the recovery of costs" (Exhibit D2-2-2, p. 3) is untrue. Unlike the renewable-connection projects, whether and when OPG starts receiving revenues from the Darlington Refurbishment depends only on the potential delays in the regulated company's own project, not on the success of a third party. And OPG has not presented any basis for believing that it faces risks of the recovery of prudently-incurred costs under conventional Board rate setting.

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[3]While the Report leaves open the possibility of a utility justifying CWIP for some project related to power delivery, this option is quite vague.

[4]The utility may also face "landowner issues, public controversy, [and] siting uncertainties" in building its own facilities, due not to opposition to the utility facilities (which is a risk with any transmission line and some other major T&D projects) but to the opposition to the generation facility.

Q: Does OPG need a current return on CWIP as an incentive to pursue the Darlington Refurbishment?

A: No. The Darlington Refurbishment is primarily an OPG initiative, selected to allow it "to maintain a significant footprint in the Ontario Electricity Marketplace." Far from being an obstacle to this project, OPG is its primary advocate. As the operator of Darlington and Pickering, OPG must have considerable internal advocacy for extending the operating life of its nuclear plants. Indeed, OPG confirms that "the decision to proceed with the refurbishment of the Darlington nuclear generating station was not, and is currently not, contingent on CWIP being included in rate base." (Exhibit L-12-5)

Q: Does Mr. Luciani suggest that the lack of CWIP would discourage the Province from providing capital to OPG for this project?

A: Oddly enough, he does make this claim. He says that "Earlier cash returns on assets with long construction periods provide more certainty to investors which should encourage a greater willingness to invest" (Exhibit D4-1-1).

When asked "does Mr. Luciani believe that the Province's willingness to invest in OPG would be increased by placing CWIP in rate base," OPG responded "OPG understands that Mr. Luciani's belief is yes, as measured on a stand-alone basis from a commercial perspective" (Exhibit L-7-10).

Since the Province has not indicated any reluctance to invest in cost-effective OPG projects without CWIP, it is not clear how its willingness to invest can be increased.

Q: Does OPG assert that the Darlington Refurbishment meets the standards the Board has established for transmission and distribution utilities to be eligibility for CWIP?

A: Yes. At Exhibit D2-2-2, p. 4, OPG claims that it meets all seven of the standards laid out by the Board at page 21 of the Report as follows:

- the need for the project
- the public interest benefits of the project
- the overall cost of the project in absolute terms
- the risks or particular challenges associated with the completion of the project
- the cost of the project in proportion to the current rate base of the utility
- the reasons given for not relying on conventional cost-recovery mechanisms
- whether the utility is otherwise obligated to undertake the project.

The Company asserts that "The first four factors above are covered within Exhibit D2-T2-S1 and its associated attachments" and that "The last three are addressed" in pages 4–9 of Exhibit D2-2-2.

Q: Does OPG demonstrate that all seven factors have been met in its filing?

A: No. As I discuss below, I see no demonstration in Exhibit D2-2-1 or elsewhere in the evidence that the Darlington Refurbishment is needed or that it is in the public interest. There are also flaws in OPG's treatment of the last three factors.

Q: Does OPG acknowledge that a demonstration of need and public interest benefits is a prerequisite for the Board allowing a current return on CWIP?

A: The Company's position is ambiguous. In addition to acknowledging the roles of need and public interest benefits in Exhibit D2-2-2, OPG agrees,

> In considering a proposal for an alternative mechanism, such as CWIP, the OEB indicated that it would evaluate a variety of factors including the need for the project and the public interest benefits. (Exhibit L-10-8)

Yet OPG then seems to contradict its position:

> The OEB did not indicate that a public interest finding was required before an alternative mechanism such as advanced recovery of CWIP would be considered. (Ibid.)

Q: Does OPG present an analysis of the need for and public interest benefits of the Darlington Refurbishment?

A: In Exhibit D2-2-1, OPG simply asserts,

> An economic feasibility assessment of the refurbishment of Darlington has indicated that this is one of the most economic generation options available to OPG to maintain a significant footprint in the Ontario Electricity Marketplace. Refurbishment of the Darlington units is also supported by the Ontario Power Authority, as discussed below, as one of the best options to meet the need for base-load generation in the Province of Ontario going forward. (Exhibit D2-2-1, p. 8)

I see no reference to the Ontario Power Authority later in Exhibit D2-2-1, but earlier in that document (p. 4) OPG says, "The need for refurbishment is also addressed in the Ontario Power Authority's Integrated Power System Plan (IPSP)."

Thus, OPG claims that the need and public-interest benefits of the Darlington Refurbishment are established by (1) an economic feasibility assessment it performed but did not provide with the filing, which established the superiority of the Darlington Refurbishment for the purpose of maintaining OPG's footprint in the Ontario power market and (2) the OPA's IPSP.

Q: Can the need and public interest benefits of the Darlington Refurbishment be established by the feasibility assessment it cited?

A: No. The assessment, summarized in Exhibit D2-2-1, page 34, compares the Darlington Refurbishment only to new nuclear construction (for which OPG has no cost estimates), Pickering B refurbishment (which OPG has previously found to be not cost-effective) and construction of a combined-cycle combustion turbine (CCCT) plant, ignoring all potential alternatives—particularly conservation and renewables, which current government policy appears to favour. In other words, only one alternative was compared to Darlington Refurbishment. As OPG acknowledged (Exhibit L-7-31), it "has not assessed other non-OPG generation options." The reason for this narrow range of the analysis may be that OPG has determined that it wants to maintain its "footprint" on the Ontario marketplace, is thus uninterested in any alternative that OPG would not own, and does not believe that it is a viable owner of renewables. This perspective is inadequate to demonstrate need or public benefits.

The assessment is also inadequate in that it compares its two alternatives solely in terms of the levelized unit cost of energy, which ignores the ability of the CCCT to operate when needed and economic and shut down when energy prices fall due to the combination of low loads and high supply (e.g., from wind or purchases). The effective cost of the CCCT thus equals its fixed costs plus is running costs when the plant is economic to run and the lower costs of economy energy when it is not economic. The assessment thus overstates the cost of the CCCT. Nuclear units cannot cycle similarly and given their low fuel costs would rarely be economic to cycle.[5]

The assessment also fails to account for the Darlington generation that would be lost during the period of the refurbishment. OPG currently projects that the first unit will be removed from service in 2015 or 2016, and be out of service for three or four years (Exhibit D2-2-1 Attachment 1, p. 5). This seems

[5]The assessment also does not value the CCCT's value in providing ancillary services (regulation, operating reserves, load following) that Darlington cannot provide.

to result in taking at least the first units out of service early, since "Based on original design assumptions, the Darlington units were expected to reach their nominal end of life between 2018 and 2020" (Exhibit D2-2-1, p.5). For Pickering B, OPG has determined that it can stretch unit life by four years at modest cost (Exhibit F2-2-3, p.4; Attachment 1, p. 27). Thus, it appears that the Darlington Refurbishment would result in lower Darlington generation for roughly 2015–2020 than operation to end of life without refurbishment. That cost is not reflected in the comparison.

Q: Was the provision of the assessment in the discovery process sufficient to establish the need and benefit for the Darlington Refurbishment, if it were not flawed?

A: No. OPG estimates that the refurbishment will cost $6 to $10 billion in 2009 overnight dollars, not including inflation and AFUDC (Exhibit L-12-49). Before applying for any special ratemaking treatment, including a current return on CWIP, OPG should be required to submit the project for a prudence review by the Board. It has not done so.

Q: Does the mention of refurbishment in the IPSP demonstrate that the Darlington Refurbishment is needed and would provide public-interest benefits?

A: No. The IPSP assumed that new nuclear (and refurbishing Pickering B) would cost $2,907/kW, and that refurbishment would be less expensive. The assumptions in the IPSP were challenged by several parties, including in my own evidence for my current clients. We estimated that new nuclear would cost at least $5,000/kW and found that a plan with no new nuclear construction and new refurbishment would be preferable to OPA's IPSP.

The Province found that the bids for new nuclear were much more expensive than the \$2,907/kW in the IPSP (press reports cited \$10,800/kW). OPG's current estimates of the costs of a Pickering-B refurbishment are also considerably greater than the \$2,907/kW assumed in the IPSP. Hence, the IPSP estimates of nuclear economics are irrelevant to any current assessment of the need or cost-effectiveness of the Darlington refurbishment. At the Minister's direction, OPA suspended the IPSP review. As a result, the IPSP evidence has not been subject to regulatory review.

Q: Has OPG adequately analyzed the Board's fifth criterion, "the cost of the project in proportion to the current rate base of the utility?"

A: No. OPG points out that total cost of the Darlington Refurbishment is \$6–\$10 billion (Exhibit D2-2-2, p. 4). However, not all this investment would be in CWIP at the same time. Exhibit L-12-3, Attachment 1, estimates that less than half the investment would occur before the first unit and common facilities enter service and are no longer in CWIP.

As I discuss in Section III.B, OPG's projection of the amount of Darlington Refurbishment CWIP is not particularly great compared to its rate base in the rate period for this proceeding.

Q: Has OPG provided an adequate rationale "for not relying on conventional cost-recovery mechanisms," the Board's sixth criterion?

A: No. As I discuss in Sections III.B and III.C, OPG has not established that it cannot finance the Darlington Refurbishment under conventional cost-recovery mechanisms or that CWIP would benefit customers.

Q: How has OPG addressed the issue of "whether the utility is otherwise obligated to undertake the project," the Board's seventh criterion?

A: The Company's evidence on this issue is limited to the observations that it

> received direction from the Province requiring OPG to undertake feasibility studies on refurbishing its existing nuclear units in 2007. Further, on February 4, 2010, the Province affirmed the November 2009 decision of OPG's Board of Directors to proceed with the definition phase of the project. (Exhibit D2-2-2, p. 9)

I read OPG's evidence as suggesting that it is "obligated to undertake the project," although the only instruction—the direction to undertake feasibility studies—does not create an obligation to proceed with construction. Provincial affirmation of an OPG proposal to conduct further studies does not obligate OPG to do anything, let alone proceed beyond the study phase.

Hence, OPG has not demonstrated that it is obligated to undertake the project beyond the definition study.

Q: What is the effect of an obligation to undertake a project on the need for CWIP?

A: In general, to the extent that a regulated entity is obligated to undertake a project, there is less need for CWIP or other incentives to encourage the entity to proceed. While OPG has obliquely suggested that the Darlington Refurbishment is dependent on CWIP in rate base—"While the deferral of inclusion of costs in rate base would tend to dampen rate shock, such an approach is unlikely to stimulate infrastructure investment" (Exhibit L-7-9)—OPG has acknowledged (Exhibit L-12-5) that it will proceed with or without CWIP treatment. The obligation may reduce the importance of the need and public benefits issues on the Board's list, if some need for CWIP can be demonstrated, but no such need has been shown. Further, the obligation would help ensure that the Board would find the expenditures prudent in the ordinary course and thus lower any risk that OPG faces without special CWIP treatment.

B. Financial Integrity

Q: How does OPG raise the issue of OPG's financial integrity in justifying its request for a current return on CWIP?

A: The evidence of Mr. Luciani quoted the Louisiana PSC to the effect that

> the recovery of a current cash return on CWIP may be needed to protect a utility's financial integrity, to maintain an acceptable credit rating, [and] to prevent an undue increase in the utility's cost of capital …. (Ex. D4-T1-S1, p. 8)

He also quoted FERC to the effect that CWIP has often been allowed "when the reliability of future service is in doubt" (ibid., p. 12).

Q: Has OPG demonstrated that a current cash return on CWIP is actually needed for any of these purposes?

A: No. In response to discovery, OPG asserted that all three of these considerations apply to OPG, but failed to provide any evidence that the lack of a return on CWIP would actually have any of the following adverse effects:

- threaten OPG's financial integrity (Exhibit L-7-1),
- reduce OPG or the Province's ability below an acceptable credit rating (Exhibit L-7-2),
- unduly increase OPG's cost of capital (Exhibit L-7-3),
- place the reliability of future service in doubt (Exhibit L-7-13).

Q: Does Mr. Luciani assert that CWIP is important in maintaining and acceptable credit rating?

A: He does. Mr. Luciani asserts that "the recovery of a current cash return on CWIP may be needed to maintain an acceptable credit rating," and that "A credit rating agency takes into account a number of items in determining utility credit ratings and a current cash return on CWIP is one of those items" (Exhibit L-7-2). However, a recent report by Standard and Poor's (Regulated U.S. Electric

Utilities Mid-Year 2010 Update, July 14 2010) rates "regulatory conditions" across 47 U.S. states.[6] Of the seven jurisdictions that received the top ranking awarded ("more credit supportive"), only two (Georgia and South Carolina) are on Mr. Luciani's list of jurisdictions allowing CWIP in rate base (Exhibit D4-1-1, p. 4) and at least two jurisdictions (Alabama and California) prohibit CWIP.[7] Of the 19 jurisdictions rated as "supportive," five are on Mr. Luciani's list, one other reports allowing CWIP, and seven never or rarely allow CWIP. One state on Mr. Luciani's list—Louisiana—is rated "less supportive." Hence, allowing CWIP in rate base is neither necessary nor sufficient to produce a favourable opinion from a rating agency.

Q: Would the Darlington CWIP be an excessive burden on OPG in the test year for this rate proceeding?

A: No. Table 1 summarizes OPG's projections of its rate base and of CWIP for Darlington Refurbishment.

Table 1: OPG Projections of Rate Base and Darlington CWIP

	2011 Plan	2012 Plan	Source
Hydro Rate Base	$3,803.4	$3,787.4	Exhibit B1-1-1, Table 1
Nuclear Rate Base	4,041.3	4,150.8	Exhibit B1-1-1, Table 2
Total Rate Base	7,844.7	7,938.2	
Darlington Refurbishment CWIP	125.5	306.0	Exhibit D2-2-2
CWIP as Percent of Rate Base	1.6%	3.9%	

As of 2012, OPG projects that Darlington Refurbishment CWIP will be only 3.9% of OPG's regulated rate base. As I show on page 7, CWIP on the Bruce

[6]http://www2.standardandpoors.com/spf/pdf/events/CRTconJuly142010.pdf, accessed August 30 2010.

[7]See the "Current Return on CWIP versus AFUDC Regulatory Survey Results," National Association of Regulatory Utility Commissioners," March 2006.

transmission project is expected to be 7.6% of Hydro One rate base by 2012, yet the Board has found that amount of CWIP did not warrant special treatment and Hydro One has not requested CWIP for the Bruce project in the last two rate proceedings.[8]

C. Alleged Customer Benefits of Accelerated Cost Recovery

Q: What customer benefits does OPG claim from charging a current return on CWIP?

A: In its filing, OPG maintains that customers would be better off paying for the Refurbishment before it occurs:

> One of the primary benefits of including CWIP in rate base is that it avoids potential rate shock and provides a smoothing of rates over time (see Ex. D4-T1-S1, section 3.1). Implicitly, this means that rates will increase gradually during the construction period consistent with the amount of expended CWIP capital that is included in rate base. This gradual increase mitigates the sudden shock that is typically associated with a multi-year project being completed and added to rate base as a single, large quantity. (Exhibit D2-2-2, p. 5)

Q: Is this front-loading of the cost recovery of the refurbishment costs likely to be a benefit to ratepayers?

A: No. Mr. Luciani recognizes that front-loading of costs is a problem with conventional rate-base cost-recovery:

[8] In addition to its regulated rate base, OPG has about $3.3 billion in other net fixed assets (Ontario Power Generation Reports 2010 Second Quarter Financial Results, p. 68).

> Because the cost of a new plant placed into service has yet to be depreciated, the revenue requirement under standard cost-of-service ratemaking associated with the recovery of the capital expended on a new plant is said to be "front end loaded". That is, the plant's revenue requirement is relatively high in the early years of the plant's life as the plant's net book value is high, and the revenue requirement declines over time as the net book value of the plant declines.
>
> While long-lived utility assets are expected to provide ratepayer benefits over their operating lifetimes, front end loading of cost recovery causes rates to increase significantly when the new asset is placed into service. (Exhibit D4-1-1, p. 9)

Unfortunately, the solution that OPG has selected and that Mr. Luciani recommends—allowing a current return on CWIP—makes the front-loading worse. When asked whether the total revenue recovery of the Darlington Refurbishment through 2025 would be greater if CWIP is in rate base than if CWIP is capitalized, OPG admitted (Exhibit L-7-7d) "this is likely to be the case on a cumulative total revenue recovered basis." In other words, the front-loading of costs into 2011–2025 would be greater with a return on CWIP than without.

The same point is evident in OPG's "illustrative" examples in Exhibit D2-2-1, Graphs 1 and 2, which show CWIP shifting costs of the first Darlington unit refurbishment from 2019–2027 forward to 2011–2018, and the costs of the entire project from (mostly) 2024–2027 to 2011–2018.[9]

Q: Does OPG offer any evidence that a return on CWIP decreases front-loading?

A: In general, OPG acknowledges that CWIP increases front-loading. OPG offers the following half-hearted argument:

> From the perspective of the rate increase required at the time of in-service, the inclusion of CWIP in rate base decreases the amount by which recovery is front-end loaded. (Exhibit L-7-7a)

[9] The ratemaking cost reductions would have to continue well beyond 2027 to balance the pre-operation cost increases. Graphs 1 and 2 extend only to 2027.

In other words, OPG suggests that, if all pre-operation cost recovery is ignored, CWIP reduces front-loading. I doubt that the Board would want to ignore pre-operation cost recovery.

Mr. Luciani complains,

> current ratepayers are enjoying the benefits of assets predominately paid for (through front end loaded revenue requirements) by past ratepayers. That is, certain valuable assets that are fully or nearly fully depreciated are relied upon by current ratepayers, but were largely paid for by prior ratepayers (Exhibit D4-1-1, p. 11).

Yet his proposed solution—allowing a current return on CWIP—would make the problem worse, by further accelerating cost recovery.

Q: Does OPG provide any quantitative analysis of the magnitude and duration of the front-loading?

A: No. The examples in Exhibit D2-2-1 are simply illustrative, and OPG was unable to provide any projection of charges with and without CWIP past 2012 (Exhibit L-7-4, Exhibit L-7-5). OPG claims that the estimates would not be useful:

> OPG declines to provide projections of payment amounts for future years as they are speculative and not relevant to the determination of payment amounts in the test period. (Exhibit L-7-5)

> OPG has only developed a very preliminary estimate of the range of costs for the Darlington Refurbishment project. OPG is not providing the requested projection [of annual revenue recovery] as it would be too speculative to be of any value. (Exhibit L-7-7b, repeated in Exhibit L-7-7c)

Even though OPG cannot project Darlington Refurbishment cost-recovery or payment amounts with and without CWIP past 2012, it somehow provides an estimate of the differences in those quantities for 2013–2014 (Exhibit L-7-4).

In terms of the duration of the front-loading, OPG is only able to assert that "the crossover point in cumulative revenue recovery should take place well before the midpoint of the asset's life." (Exhibit L-7-7a, Exhibit L-7-7d)

Including some eight years of payments prior to the beginning of the refurbishment's life, the midpoint for a 30-year asset (as projected for the Darlington Refurbishment) would be 23 years into the payment stream. Any delay in the completion of the refurbishment would add to the period in which customers pay for CWIP without receiving any benefits.[10]

The Company's undocumented assertion about the payback period does not appear to take the time value of money (or even inflation) into account, and implicitly assumes that customers are indifferent between a 2011 dollar in 2011 and an inflated 2027 dollar in 2027. In real inflation-adjusted terms or present-value terms, break-even would occur even later. For a customer who is not on the system long enough (e.g., a residential customer who dies, a commercial customer that goes out of business), or one with a discount rate higher than OPG's AFUDC rate, break-even would never occur.

Q: Has OPG determined that customers would prefer to pay for the Darlington Refurbishment before it is in service, rather than paying when the refurbishment starts providing benefits?

A: Apparently not. OPG has not surveyed Ontario consumers to determine their preferences (Exhibit L-7-9).

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[10]For example, the Canadian Nuclear Safety Commission's approval of Pickering B's Environment Assessment took 31 months, compared to the 18 months OPG has allowed for the same process for Darlington (Exhibit L-7-22) and the Final Pickering B Integrated Safety Review was submitted "close to two years later than originally planned due mainly to evolving regulatory requirements and significant levels of review required" (Exhibit L-7-24). In addition, "the specific Darlington reactor design has never undergone refurbishment" (Exhibit L-7-32).

Q: Is recovery of project costs prior to operation of the project common in other contexts?

A: No. Non-utility power producers are generally paid for energy and capacity as they provide it, not before the plant is completed. Customers do not usually pay for the construction of automobiles, restaurants, stores, houses, or apartments before they are built. Users pay for those investments when they buy, rent or shop in them.

Mr. Luciani quotes with approval a report that claims,

> A city collects taxes from today's parents for buildings that will benefit future students. Taxpayers pay today for mass transit projects that will benefit tomorrow's riders (Exhibit D4-1-1, pp. 11–12).

In general, schools and transit project are paid for by bonds and operating subsidies that are paid by taxpayers (and riders) during the life of the projects.[11] Oddly, Mr. Luciani does not appear to know whether the document he relies on is correct or relevant:

> OPG understands that Mr. Luciani has not examined school and transit project financing, and does not know the extent to which school buildings and transit projects are funded by short-term or long-term bonds or pay-as-you-go arrangements. (Exhibit L-7-11)

Note that OPG's response does not provide any evidence that taxpayers are commonly charged for schools or transit before the facilities are in operation in the way that the requested CWIP return would charge for the refurbishment before it is in service.

The Company notes it "has a commercial mandate from its shareholder to operate on a financially sustainable basis and maintain the value of its assets…"

[11] The quote is correct if it intends that the building and projects are in operation "today" (as that term is used in the quote), but that situation is the same as conventional utility ratemaking, not the accelerated cost recovery associated with a return on CWIP.

(Exhibit L-7-10). Since most commercial enterprises recover the costs of their investments after those projects are in service, OPG's "commercial mandate" would normally exclude CWIP. Certainly, neither financial sustainability nor maintaining the value of assets requires a current return on CWIP. Curiously, OPG concludes (ibid), "Inclusion of CWIP in rate base is consistent with this commercial mandate.

Q: Does Mr. Luciani suggest that customers would benefit from the Darlington Refurbishment during the construction period?

A: Yes. He asserts,

> there are other rate impacts associated with the new assets while under construction. The utility, for example, may not enter into the same amount of longer-term contracts, or may not build as many shorter-term assets given that a baseload plant will be coming into service. That is, the new plants will affect actual utility costs and rates during the construction period with or without CWIP in rates. (Exhibit D4-1-1, p. 12)

In other words, he suggests that Ontario consumers would benefit during 2011–2018, as OPG would avoid entering into long-term purchased-power contracts and building other plants in that period.

Q: Is there any validity to Mr. Luciani's claims?

A: No. There is no substance to these assertions. The refurbishment may benefit ratepayers after the refurbished units return to service, but it imposes costs during the construction period, as the following arguments suggest:

- The Company admits that it would not have signed any "longer-term contracts in the absence of Darlington Refurbishment" (Exhibit L-7-12(a)).
- Any long-term contracts would be signed by OPG (ibid.), which typically pays for generation only as energy and capacity is delivered.

- The Company is unable to explain why the costs of a hypothetical long-term contract to replace the Darlington Refurbishment would be reflected in rates during the refurbishment period (Exhibit L-7-12(b)).
- The refurbishment would not avoid the need for contracts during the construction period. On the contrary, it would reduce Darlington generation, potentially causing OPG to contract for additional power during that period.
- Asked to define and "describe all the 'shorter-term assets' that OPG would build in the absence of the Darlington Refurbishment," OPG could not identify any such assets and does not explain why the Darlington Refurbishment would avoid any such shorter-term assets (Exhibit L-7-12 (c) and (d)).

Q: Is front-loading of recovery ever justified as a benefit to rate payers?

A: Front-loading (or delaying) one cost component may be justified if it helps to offset other cost components. For example, if Ontario ratepayers were expected to experience falling rates and bills in 2011–2018 (perhaps due to refunds or the end of above-market contracts), followed by rate increases after 2018, moving some costs forward might be justified to avoid customer confusion as prices fall and rise, and perhaps to avoid a massive increase in 2019 or 2020.

Q: Has OPG demonstrated that 2011–2018 would be a better period for incremental revenue recovery than after 2023?

A: No. OPG has no projection of its own rates or any of the other components to charges to Ontario electricity consumers (Exhibits L-7-5, L-7-6). [12]

[12] Paradoxically, even though OPG claims to have no estimate of its rates after 2012, it claims to be able to determine the percentage rate increase (over an unknown rate) when the Darlington Refurbishment would enter service, to precision of 0.1% (Exhibit D2-2-2, p. 6).

Q: Is 2011–2018 a particularly good time to be recovering costs from ratepayers?

A: Many considerations suggest that the next several years will not be a good time to be voluntarily increasing rates, including the effects of the following events:

- The loss of Darlington generation starting in 2015 or 2016, as the refurbishment of the first unit(s) begin. Even if the market energy price is just $40/MWh more than Darlington's variable operating costs, each Darlington unit out of service would cost consumers about $250 million annually.
- The commercial operation of the restarted and refurbished Bruce A plant, with payments for two units starting late in 2011 and the subsequent units coming on line in 2012 and 2013 ("A Progress Report on Electricity Supply, First Quarter 2010," Ontario Power Authority, p. 3). That project is expected to cost about $6 billion.
- The in-service dates of 600 MW of OPA renewable contracts under the RESOP in 2011, with another 380 MW in 2012 and 2013 (ibid.).
- The in-service dates of 408 MW of OPA clean-energy contracts 2011, with another 280 MW in 2012 (ibid.).
- Operation of a large portion of the 2,533 MW of feed-in-tariff projects to which OPA has offered contracts, plus some of the 2,388 MW awaiting the results of the Economic Connection Test (ibid., p. 5). These feed-in-tariff contracts have prices ranging from 10.4¢/kWh to 19.5¢/kWh, with solar prices up to 80.2¢/kWh. The total payments under the first set of contract offers would be about $500 million annually, if they are all completed.
- All of OPG's 6,000 MW of coal plants will be shut down or converted to alternative fuel by 2014, starting with about 1,000 MW at Lambton and Nanticoke in October 2010. As the coal units retire, market energy prices will tend to rise in those hours in which the units would have operated. The

market-price effect will be increased by the loss of generation from Darlington and Bruce 3 and 4 for various periods and offset by the addition of Bruce 1 and 2 and contract purchases.

- Hydro One projects transmission additions of $871 million in 2011 and $1,619 million in 2012, compared to annual additions of $320–$500 million in 2005–2008 (EB-2010-0002, Exhibit D1-1-2; EB-2008-0272, Exhibit D2-3-3). Annual transmission additions seem likely to remain in the $1,000–$1,500 million range for some years.[13]

Adding CWIP recovery to all of these other cost increases would concentrate the burden on customers in those years.

Q: Does OPG recognize its responsibility to take into account overall costs to consumers, rather than simply the distribution of the cost recovery for one plant over time?

A: Yes. In explaining its decision to modestly extend the life of Pickering B rather than shut that plant down, OPG includes the consideration of the

[13]While plans are less advanced for transmission projects that will enter rates after 2012, Hydro One expects major development expenditures in 2011/12 for $412 million in projects it expects to enter service in 2013, $560 million for 2014 projects, and $430 million for a single project to be completed in 2015 (EB-2010-0002, Exhibit D1-3-3, Appendix A, Tables 2–4 and 6–8). In addition, Hydro One (ibid.) expects to make smaller development investments in 2011/12 for $1,400 million in projects that would enter service in 2013–15 or perhaps a little later. Since many development projects have only two or three years of cash flow, many projects that will come on line after 2012 would not be in Hydro One's current projections. Nor does Hydro One project post-2012 additions of sustaining, operations or shared-services capital, which average about $500 million annually in 2011–2012. Sustaining capital additions have increased dramatically over the last few years, due to the age and condition of transmission substations and other equipment (EB-2010-0002, Exhibit D1-3-2).

> need to manage the overall availability of OPG's nuclear fleet during the period following the shutdown of OPG's coal-fired units and during the period when major nuclear refurbishments are expected to be executed in the province. (Exhibit L-1-70)

Unfortunately, OPG does not appear to have taken this approach when considering whether to dump additional costs onto consumers in 2011–2018.

D. Other Construction-Work-In-Progress Issues

Q: How does allowing a current return on CWIP "impact on efficient utility management," (Board Report p. 8)?

A: Allowing a current return on CWIP reduces performance pressure on utility management, in the following ways:

- With CWIP, the costs of delay are automatically passed on to ratepayers, reducing the pressure to get projects completed and into service.
- The apparent cost of a project is reduced by forcing customers to pay for the project prior to its in-service date. Hiding part of the cost complicates prudence reviews, especially determining the cost of questionable decisions.
- Understating the final cost of the project also complicates comparison of the project cost to alternatives that capitalize the carrying cost (such as power purchases). Management is under less pressure to demonstrate the cost-effectiveness of their projects.

Q: Does allowing a current return on CWIP "reduce a project's total net present value cost," as OPG asserts in Exhibit L-1-11?

A: Not really. If the discount rate and the AFUDC rate are both set at the same annual rate (such as the utility's average cost of capital), the present value of the project revenue requirements will be the same with a current return on CWIP as with AFUDC accrual. If the revenue requirements are discounted at customer discount rates, the results will vary; for customers with short planning horizons and/or high costs of capital (e.g., the elderly, the poor, the financially over-stretched, businesses living on lines of credit, households financed with credit cards), the present value of revenue requirements will be higher with CWIP than without.

IV. Differential Cost of Capital

Q: Why should the Board apply separate costs of capital to OPG's two regulated services, nuclear and hydro-electric generation?

A: Nuclear power, with its history of cost overruns, delays, poor performance, long shutdowns, and early retirements is clearly more risky than hydro-electric generation. As Venkataraman & Cortright (2010, p. 3–4, notes to Table 1), observed in using a base 15% equity return for a nuclear plant, compared to 10% for a gas combined-cycle plant, "Nuclear is a higher-risk investment that requires correspondingly higher returns."[14] The same report notes (p. 4) "no company would likely finance a nuclear plant today without a loan guarantee." Neither statement is true of hydro-electric plants.

Using the same cost of capital for both segments of OPG's benefits overstates the costs of hydro-electric projects and understates that of nuclear projects.

[14]Venkataraman, Swami, and Richard Cortright, Jr. 2010 "The Economics of U.S. Nuclear Power: Natural Gas Prices and Loan Guarantees Are Key to Viability" *Standard & Poor's Global Credit Portal Ratings Direct* (August 16 2010).

Q: Have you estimated the differential in capital costs between these two segments of OPG's regulated operations?

A: Not for this proceeding. In EB-2007-0905, I used data provided by OPG to estimate that differential, as shown in Exhibit PLC-2. I understand that other parties will address this question in the current proceedings.

Q: What decisions might be affected by using more realistic estimates of the cost of capital by OPG business segment?

A: A good example of the sort of decisions affected by the imputed cost of capital is the Darlington Refurbishment. Using its proposed merged cost of capital of 46% equity at 9.85%, OPG estimates that the project will cost 6¢ to 8¢/kWh (Exhibit D2-2-1, p. 5; Exhibit L-10-3). Using a nuclear-specific cost of capital of 70% equity at 18%, OPG estimates a cost of 10¢ to 14¢/kWh at an 82% capacity factor and 9¢ to 18¢/kWh over a range of capacity factors from 64.2% to 87% (Exhibit L-10-6). Since OPG abandoned the Pickering B refurbishment due in part to its projected cost of 7.5¢ to 9.9¢ (Exhibit L-2-26, p. 4), varying the cost of capital used in the analysis of nuclear projects can easily determine whether the projects are considered to be cost-effective.

The Company indicates that it would consider the Darlington Refurbishment to be economic so long as there is any slim possibility that it might be competitive against a constrained set of alternatives

> unless the Levelized Unit Energy Cost ('LUEC') consistently exceeds the LUEC for other baseload options with similar load meeting characteristics for a full range of input variables. (Exhibit L-7-29)

The Board may take a more-even-handed approach to comparing the costs of the Darlington Refurbishment to alternatives for serving consumer loads.

Q: Does this conclude your testimony?

A: Yes.

Exhibit PLC-1

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SUMMARY OF PROFESSIONAL EXPERIENCE

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

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

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

EDUCATION

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

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Chi Epsilon (Civil Engineering)

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Institute Award, Institute of Public Utilities, 1981.

PUBLICATIONS

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

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"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.” 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.

“Increasing Market Share Through Energy Efficiency.” 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.

EXPERT TESTIMONY

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

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

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

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

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

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

4. **MDPU** 19494; Phase II; Boston Edison Company Construction Program; Massachusetts Attorney General; April 1 1979.

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

5. **MDPU** 19494; Phase II; Boston Edison Company Construction Program; Massachusetts Attorney General; April 1 1979.

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

6. **ASLB, NRC** 50-471; Pilgrim Unit 2, Boston Edison Company; Commonwealth of Massachusetts; June 29 1979.

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

7. **MDPU** 19845; Boston Edison Time-of-Use Rate Case; Massachusetts Attorney General; December 4 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 S.C. Geller. Testimony eventually withdrawn due to delay in case.

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

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

9. **MDPU** 20248; Petition of MMWEC to Purchase Additional Share of Seabrook Nuclear Plant; Massachusetts Attorney General; June 2 1980.

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

10. **MDPU** 200; Massachusetts Electric Company Rate Case; Massachusetts Attorney General; June 16 1980.

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

11. **MEFSC** 79-33; Eastern Utilities Associates 1979 Forecast; Massachusetts Attorney General; July 16 1980.

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

12. **MDPU** 243; Eastern Edison Company Rate Case; Massachusetts Attorney General; August 19 1980.

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

13. **Texas PUC** 3298; Gulf States Utilities Rate Case; East Texas Legal Services; August 25 1980.

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

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

    Cost comparison methodology; nuclear cost estimates; cost of conservation, co-generation, and solar.

15. **MDPU** 472; Recovery of Residential Conservation Service Expenses; Massachusetts Attorney General; December 12 1980.

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

16. **MDPU** 535; Regulations to Carry Out Section 210 of PURPA; Massachusetts Attorney General; January 26 1981 and February 13 1981.

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

17. **MEFSC** 80-17; Northeast Utilities 1980 Forecast; Massachusetts Attorney General; March 12 1981 (not presented).

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

18. **MDPU** 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. **MDPU** 1048; Boston Edison Plant Performance Standards; Massachusetts Attorney General; May 7 1982.

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

20. **DCPSC** FC785; Potomac Electric Power Rate Case; DC People's Counsel; July 29 1982.

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

21. **NHPUC** DE1-312; Public Service of New Hampshire-Supply and Demand; Conservation Law Foundation, et al.; October 8 1982.

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

22. **Massachusetts 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. **Illinois Commerce Commission** 82-0026; Commonwealth Edison Rate Case; Illinois Attorney General; October 15 1982.

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

24. **New Mexico PSC** 1794; Public Service of New Mexico Application for Certification; New Mexico Attorney General; May 10 1983.

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

25. **Connecticut Public Utility Control Authority** 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. **MDPU** 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. **Massachusetts 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. **Connecticut Public Utility Control Authority** 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. **MEFSC** 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. **Michigan 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. **MDPU** 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. **MDPU** 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. **Michigan 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. **MDPU** 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. **Pennsylvania 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. **NHPUC** 84-200; Seabrook Unit 1 Investigation; New Hampshire Public Advocate; November 15 1984.

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

39. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1985 Automobile Insurance Rates; Massachusetts Attorney General; November 1984.

    Profit margin calculations, including methodology and implementation.

40. **MDPU** 84-152; Seabrook Unit 1 Investigation; Massachusetts Attorney General; December 12 1984.

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

41. **Maine PUC** 84-120; Central Maine Power Rate Case; Maine PUC Staff; December 11 1984.

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

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

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

43. **MDPU** 1627; Massachusetts Municipal Wholesale Electric Company Financing Case; Massachusetts Executive Office of Energy Resources; January 14 1985.

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

44. **Vermont PSB** 4936; Millstone 3; Costs and In-Service Date; Vermont Department of Public Service; January 21 1985.

    Construction schedule and cost of completing Millstone Unit 3.

45. **MDPU** 84-276; Rules Governing Rates for Utility Purchases of Power from Qualifying Facilities; Massachusetts Attorney General; March 25 1985, and October 18 1985.

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

46. **MDPU** 85-121; Investigation of the Reading Municipal Light Department; Wilmington (MA) Chamber of Commerce; November 12 1985.

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

47. **Massachusetts 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. **New Mexico PSC** 1833, Phase II; El Paso Electric Rate Case; New Mexico Attorney General; December 23 1985.

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

49. **Pennsylvania PUC** R-850152; Philadelphia Electric Rate Case; Utility Users Committee and University of Pennsylvania; January 14 1986.

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

50. **MDPU** 85-270; Western Massachusetts Electric Rate Case; Massachusetts Attorney General; March 19 1986.

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

51. **Pennsylvania PUC** R-850290; Philadelphia Electric Auxiliary Service Rates; Albert Einstein Medical Center, University of Pennsylvania and AMTRAK; March 24 1986.

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

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

    Recommendations for Power Plant Performance Standards for Palo Verde nuclear units 1, 2, and 3.

53. **Illinois Commerce Commission** 86-0325; Iowa-Illinois Gas and Electric Co. Rate Investigation; Illinois Office of Public Counsel; August 13 1986.

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

54. **New Mexico PSC** 2009; El Paso Electric Rate Moderation Program; New Mexico Attorney General; August 18 1986. (Not presented).

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

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

55. **City of Boston, Public Improvements Commission;** Transfer of Boston Edison District Heating Steam System to Boston Thermal Corporation; Boston Housing Authority; December 18 1986.

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

56. **Massachusetts 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. **MDPU** 87-19; Petition for Adjudication of Development Facilitation Program; Hull (MA) Municipal Light Plant; January 21 1987.

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

58. **New Mexico PSC** 2004; Public Service of New Mexico Nuclear Decommissioning Fund; New Mexico Attorney General; February 19 1987.

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

59. **MDPU** 86-280; Western Massachusetts Electric Rate Case; Massachusetts Energy Office; March 9 1987.

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

60. **Massachusetts Division of Insurance** 87-9; 1987 Workers' Compensation Rate Filing; State Rating Bureau; May 1987.

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

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

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

62. **Minnesota PUC** ER-015/GR-87-223; Minnesota Power Rate Case; Minnesota Department of Public Service; August 17 1987.

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

63. **Massachusetts Division of Insurance** 87-27; 1988 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; September 2 1987. Rebuttal October 8 1987.

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

64. **MDPU** 88-19; Power Sales Contract from Riverside Steam and Electric to Western Massachusetts Electric; Riverside Steam and Electric; November 4 1987.

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

65. **Massachusetts Division of Insurance** 87-53; 1987 Workers' Compensation Rate Refiling; State Rating Bureau; December 14 1987.

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

66. **Massachusetts Division of Insurance;** 1987 and 1988 Automobile Insurance Remand Rates; Massachusetts Attorney General and State Rating Bureau; February 5 1988.

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

67. **MDPU** 86-36; Investigation into the Pricing and Ratemaking Treatment to be Afforded New Electric Generating Facilities which are not Qualifying Facilities; Conservation Law Foundation; May 2 1988.

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

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

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

69. **MDPU** 88-67; Boston Gas Company; Boston Housing Authority; June 17 1988.

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

70. **Rhode Island PUC** Docket 1900; Providence Water Supply Board Tariff Filing; Conservation Law Foundation, Audubon Society of Rhode Island, and League of Women Voters of Rhode Island; June 24 1988.

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

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

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

72. **Vermont PSB** 5270, Module 6; Investigation into Least-Cost Investments, Energy Efficiency, Conservation, and the Management of Demand for Energy; Conservation Law Foundation, Vermont Natural Resources Council, and Vermont Public Interest Research Group; September 26 1988.

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

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

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

74. **MDPU** 88-67, Phase II; Boston Gas Company Conservation Program and Rate Design; Boston Gas Company; March 6 1989.

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

75. **Vermont PSB** 5270; Status Conference on Conservation and Load Management Policy Settlement; Central Vermont Public Service, Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group, and Vermont Department of Public Service; May 1 1989.

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

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

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

77. **MDPU** 89-100; Boston Edison Rate Case; Massachusetts Energy Office; June 30 1989.

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

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

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

79. **MDPU** 89-72; Statewide Towing Association, Police-Ordered Towing Rates; Massachusetts Automobile Rating Bureau; September 13 1989.

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

80. **Vermont PSB** 5330; Application of Vermont Utilities for Approval of a Firm Power and Energy Contract with Hydro-Quebec; Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group; December 19 1989. Surrebuttal February 6 1990.

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

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

81. **MDPU** 89-239; Inclusion of Externalities in Energy Supply Planning, Acquisition and Dispatch for Massachusetts Utilities; December 1989; April 1990; May 1990.

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

82. **California PUC**; Incorporation of Environmental Externalities in Utility Planning and Pricing; Coalition of Energy Efficient and Renewable Technologies; February 21 1990.

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

83. **Illinois Commerce Commission** Docket 90-0038; Proceeding to Adopt a Least Cost Electric Energy Plan for Commonwealth Edison Company; City of Chicago; May 25 1990. Joint rebuttal testimony with David Birr, August 14 1990.

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

84. **Maryland PSC** 8278; Adequacy of Baltimore Gas & Electric's Integrated Resource Plan; Maryland Office of People's Counsel; September 18 1990.

    Rationale for demand-side management, and 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. **Indiana Utility Regulatory Commission;** Integrated Resource Planning Docket; Indiana Office of Utility Consumer Counselor; November 1 1990.

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

86. **MDPU** 89-141, 90-73, 90-141, 90-194, and 90-270; Preliminary Review of Utility Treatment of Environmental Externalities in October QF Filings; Boston Gas Company; November 5 1990.

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

87. **MEFSC** 90-12/90-12A; Adequacy of Boston Edison Proposal to Build Combined-Cycle Plant; Conservation Law Foundation; December 14 1990.

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

88. **Maine PUC** 90-286; Adequacy of Conservation Program of Bangor Hydro Electric; Penobscot River Coalition; February 19 1991.

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

89. **Virginia State Corporation Commission** PUE900070; Order Establishing Commission Investigation; Southern Environmental Law Center; March 6 1991.

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

90. **MDPU** 90-261-A; Economics and Role of Fuel-Switching in the DSM Program of the Massachusetts Electric Company; Boston Gas Company; April 17 1991.

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

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

NEPCo rates for power purchases from the NESWC plant. Fuel price and avoided cost projections vs. realities.

92. **Vermont PSB** 5491; Cost-Effectiveness of Central Vermont's Commitment to Hydro Quebec Purchases; Conservation Law Foundation; July 19 1991.

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

93. **South Carolina PSC** 91-216-E; Cost Recovery of Duke Power's DSM Expenditures; South Carolina Department of Consumer Affairs; September 13 1991. Surrebuttal October 2 1991.

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

94. **Maryland PSC** 8241, Phase II; Review of Baltimore Gas & Electric's Avoided Costs; Maryland Office of People's Counsel; September 19 1991.

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

95. **Bucksport Planning Board;** AES/Harriman Cove Shoreland Zoning Application; Conservation Law Foundation and Natural Resources Council of Maine; October 1 1991.

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

96. **MDPU** 91-131; Update of Externalities Values Adopted in Docket 89-239; Boston Gas Company; October 4 1991. Rebuttal, December 13 1991.

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

97. **Florida PSC** 910759; Petition of Florida Power Corporation for Determination of Need for Proposed Electrical Power Plant and Related Facilities; Floridians for Responsible Utility Growth; October 21 1991.

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

98. **Florida PSC** 910833-EI; Petition of Tampa Electric Company for a Determination of Need for Proposed Electrical Power Plant and Related Facilities; Floridians for Responsible Utility Growth; October 31 1991.

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

99. **Pennsylvania PUC** I-900005, R-901880; Investigation into Demand Side Management by Electric Utilities; Pennsylvania Energy Office; January 10 1992.

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

100. **South Carolina PSC** 91-606-E; Petition of South Carolina Electric and Gas for a Certificate of Public Convenience and Necessity for a Coal-Fired Plant; South Carolina Department of Consumer Affairs; January 20 1992.

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

101. **MDPU** 92-92; Adequacy of Boston Edison's Street-Lighting Options; Town of Lexington; June 22 1992.

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

102. **South Carolina PSC** 92-208-E; Integrated Resource Plan of Duke Power Company; South Carolina Department of Consumer Affairs; August 4 1992.

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

103. **North Carolina Utilities Commission** E-100, Sub 64; Integrated Resource Planning Docket; Southern Environmental Law Center; September 29 1992.

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

104. Ontario Environmental Assessment Board Ontario Hydro Demand/Supply Plan Hearings; *Environmental Externalities Valuation and Ontario Hydro's Resource Planning* (3 vols.); October 1992.

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

105. Texas PUC 110000; Application of Houston Lighting and Power Company for a Certificate of Convenience and Necessity for the DuPont Project; Destec Energy, Inc.; September 28 1992.

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

106. Maine Board of Environmental Protection; In the Matter of the Basin Mills Hydroelectric Project Application; Conservation Intervenors; November 16 1992.

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

107. Maryland PSC 8473; Review of the Power Sales Agreement of Baltimore Gas and Electric with AES Northside; Maryland Office of People's Counsel; November 16 1992.

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

108. North Carolina Utilities Commission E-100, Sub 64; Analysis and Investigation of Least Cost Integrated Resource Planning in North Carolina; Southern Environmental Law Center; November 18 1992.

Demand-side management cost recovery and incentive mechanisms.

109. South Carolina PSC 92-209-E; In Re Carolina Power & Light Company; South Carolina Department of Consumer Affairs; November 24 1992.

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

110 Florida Department of Environmental Regulation 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. Maryland PSC 8487; Baltimore Gas and Electric Company, Electric Rate Case; January 13 1993. Rebuttal Testimony: February 4 1993.

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

112. **Maryland PSC** 8179; for Approval of Amendment No. 2 to Potomac Edison Purchase Agreement with AES Warrior Run; Maryland Office of People's Counsel; January 29 1993.

Economic analysis of proposed coal-fired cogeneration facility.

113. A. **Michigan 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.

DSM planning, program designs, potential savings, and avoided costs.

115. **Michigan 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. **Illinois Commerce Commission** 92-0268, Electric-Energy Plan for Commonwealth Edison; City of Chicago. Direct testimony, 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. **Vermont 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. **Florida 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. **Vermont 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. **MDPU** 94-49, Boston Edison integrated resource-management plan; Massachusetts Attorney General. August 1994.

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

122. **Michigan 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. **Michigan 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. **New Jersey Board of Regulatory Commissioners** 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. **Michigan 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. **Michigan 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. **North Carolina Utilities Commission** 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. **DCPSC** Formal 917, 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. **Ontario Energy Board** EBRO 490, DSM cost recovery and lost-revenue–adjustment mechanism for Consumers Gas Company; Green Energy Coalition. April 1995.

     DSM 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. **MDPU** 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. **Maryland 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. **North Carolina Utilities Commission** E-2, Sub 669. December 1995.

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

136. **Arizona Commerce Commission** 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 **Vermont PSB** 5835; Vermont Department of Public Service. February 1996.

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

139. **Maryland 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. A. **MDPU** 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. **MDPU** DPU 96-70; Massachusetts Attorney General. July 1996.

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

142. **MDPU** DPU 96-60; Massachusetts Attorney General. Direct testimony, July 1996; surrebuttal, August 1996.

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

143. **Maryland PSC** 8725; 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. **New Hampshire 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. **Ontario Energy Board** EBRO 495, LRAM and shared-savings incentive for DSM performance of Consumers Gas; Green Energy Coalition. March 1997.

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

146. **New York PSC** Case 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. **Vermont 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. **MDPU** 96-23, Boston Edison restructuring settlement; Utility Workers Union of America. September 1997.

Performance incentives proposed for the Boston Edison company.

149. **Vermont 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. **MDPU** 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. **MDTE** 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. **NH 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. **Maryland PSC** 8774; APS-DQE merger; Maryland Office of People's Counsel. February 1998.

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

154. **Vermont 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. **MDTE** 98-89, purchase of Boston Edison municipal streetlighting, Towns of Lexington and Acton. Affidavit, August 1998.

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

157. **Vermont 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. **MDTE** 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. **Maryland 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. **Maryland 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. **Maryland 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. **Connecticut 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. **Connecticut 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. **Washington 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. **Connecticut 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. **Connecticut 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. Virginia 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. **Ontario 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. **Connecticut 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. **Connecticut Superior Court** CV 99-049-7239; Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. Affidavit, December 1999.

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

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

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

173. **Ontario 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. **Connecticut 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. **Ontario 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. **NY 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. **MEFSB** 97-4; MMWEC gas-pipeline proposal; Town of Wilbraham, Mass. June 2000.

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

180. **Connecticut 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. **Connecticut 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. **MDTE** 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. **Connecticut 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. **Vermont 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. **New Jersey 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. **New Jersey 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. **Connecticut 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. **New Jersey 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. **NY 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. **MDTE** 01-56, Berkshire Gas Company; Massachusetts Attorney General. October 2001.

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

191. **New Jersey 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. **Vermont PSB** 6545; Vermont Yankee proposed sale; Vermont Department of Public Service. Direct, 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. **Connecticut 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. **Vermont 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. **Connecticut 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. **Connecticut 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. **Ontario EB** RP-2002-0120; Review of transmission-system code; Green Energy Coalition. October 2002.

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

198. **New Jersey 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. **Connecticut 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. **Connecticut DPUC** 03-07-01; CL&P transitional standard offer; AARP. November 2003.

Application of rate cap. Legislative intent.

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

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

203. **NY PSC** Cases 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. **NY 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. **Ontario EB** 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. **MDTE** 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. **NY 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. **NY 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. **Maryland 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. **British Columbia Utilities Commission** Project No. 3698388, British Columbia Hydro resource-acquisition plan; British Columbia Sustainable Energy Association and Sierra Club of Canada BC Chapter. Direct, September 2005.

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

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

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

212. **Connecticut DPUC** 03-07-01RE03 & 03-07-15RE02; incentives for power procurement; Connecticut Office of Consumer Counsel. Direct, September 2005. Additional Testimony, 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. **Connecticut 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. **Ontario 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. **Ontario Energy Board** Case 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. **Indiana Utility Regulatory Commission** Cause Nos. 42943 and 43046; Vectren Energy DSM proceedings; Citizens Action Coalition. Direct, June 2006.

Rate decoupling and energy-efficiency goals.

217. **Pennsylvania PUC** Docket No. 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. **Pennsylvania PUC** Docket No. 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. **Connecticut 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 September and October 2006.

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

220. **Connecticut 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 August and November 2006; March, September, October, and November 2007; February, April, and May 2008.

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

221. **NY 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. **Connecticut 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. **PUCO** Case No. 05-1444-GA-UNC; recovery of conservation costs, decoupling, and rate-adjustment mechanisms for Vectren Energy Delivery of Ohio; Ohio Consumers' Counsel. Direct, February 2007.

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

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

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

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

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

226. **Connecticut DPUC** Docket 07-04-24, Review of capacity contracts under Energy Independence Act; Connecticut Office of Consumer Counsel, Joint Direct Testimony 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. **NY PSC** Case 07-E-0524, Consolidated Edison electric rates; City of New York. Direct, September 2007.

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

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

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

230. **CDPUC 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. **Ontario EB-2007-0905,** Ontario Power Generation payments; Green Energy Coalition. Direct, 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. Direct, July 2008

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

233. **Ontario EB-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. **NY PSC** Case 08-E-0596, Consolidated Edison electric rates; City of New York. Direct, 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. **CDPUC 08-07-01**, integrated resource plan; Connecticut Office of Consumer Counsel. Direct, 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. **Manitoba PUB** 2008 MH EIIR, Manitoba Hydro intensive industrial rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. Direct, November 2008.

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

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

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

238. **Vermont 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. **Nova Scotia Review Board** P-884(2), Nova Scotia Power DSM and cost recovery, Nova Scotia Consumer Advocate. May 2009.

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

240. **Nova Scotia Review Board** P-172, 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. **Connecticut Siting Council** 370A, Connecticut Light & Power transmission projects; Connecticut Office of Consumer Counsel. Direct, July 2009.

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** Docket No. 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** Docket No. 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** Docket No. R-2009-2139884, Philadelphia Gas Works energy efficiency and cost recovery; Philadelphia Gas Works. Direct, December 2009.

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

246. **Ark. PSC** Docket No. 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.

247. **Ark. PSC** Docket No. 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.

248. **Ark. PSC** Docket No. 08-137-U, Generic rate-making; National Audubon Society and Audubon Arkansas. Direct, March 2010.

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

249. **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.

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

251. Maryland PSC 9230, Baltimore Gas & Electric rates; Maryland Office of People's Counsel. Direct, Direct, July 2010.

Allocation of gas-distribution costs.

PLC 8/11/2010

Exhibit PLC-2

PROVINCE OF ONTARIO

BEFORE THE ONTARIO ENERGY BOARD

Application Ontario Power Generation	)	
Inc. for Determination of Payment	)	**EB-2007-0905**
Amounts for the Output of Certain of Its	)	
Generating Facilities	)	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

GREEN ENERGY COALITION, PEMBINA INSTITUTE, AND ONTARIO SUSTAINABLE ENERGY ASSOCIATION

Resource Insight, Inc.

APRIL 18, 2008

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APPENDICES

I. Identification & 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 honor 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, 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 Appendix 1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than two hundred times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in Ontario, Alberta, Manitoba and 24 states, as well as the two US Federal agencies.

Q: Have you previously presented evidence before the Ontario Energy Board?

A: Yes. I filed evidence and/or testified before the Ontario Environmental Assessment Board in Ontario Hydro's Demand/Supply Plan hearings in 1992, and before the OEB in the following dockets:

- EBRO 490, DSM cost recovery and lost-revenue adjustment mechanism for Consumers Gas Company;
- EBRO 495, LRAM and shared-savings incentive for DSM performance of Consumers Gas;
- RP-1999-0034, Ontario Performance-Based Rates for electric distribution utilities;
- RP-1999-0044, Ontario Hydro transmission-cost allocation and rate design;
- RP-1999-0017,Union Gas proposal for performance-based rates;
- RP-2002-0120, Ontario transmission-system code;
- RP-2004-018, cost recovery and DSM for electric-distribution utilities;
- EB-2005-0520, rate design and cost allocation for Union Gas firm customers;
- EB-2006-0021; gas utility DSM planning and cost recovery.

II. Introduction

Q: On whose behalf are you testifying?

A: My testimony is sponsored by the Green Energy Coalition, Pembina Institute, and Ontario Sustainable Energy Association.

Q: What is the purpose of your testimony?

A: My clients have asked me to review the policy implications of Ontario Power Generation's (OPG) request for a single blended cost of capital for its two very different regulated operating segments: nuclear and hydroelectric operations.

Q: What do your conclude?

A: I conclude that the Board should set separate costs of capital—that is, cost of equity and capital structure—for each of OPG's operational segments, both to facilitate the tracking of costs and to improve OPG's decision-making with regard to investments.

III. Differences in Costs of Capital

Q: What determines the cost of capital for various lines of business?

A: Entities that raise capital in the capital markets must pay a return on debt and offer an expected return on equity that attract investors. Investors have other things they can do with their money (buy other debt, equities, real estate, commodities, or other investments), and will only invest if the expected return adequately compensates them for such factors as taxes and risk.

Every business operation faces risks related to the variability of costs and revenues. In most cases, the equity holders assume most of the risk; current dividends may decrease or disappear in difficult financial times, and stock prices fall when the market observes adverse changes in the operation's prospects. In contrast, debt holders usually paid the same amount regardless of the financial performance of the firm. Nonetheless, to the extent that investors are concerned about the prospect of continuing interest payments or repayment of capital, the price of the bonds can fall even if interest payments continue. All else equal, the less equity that supports a given investment, the greater the risk borne by each dollar of equity and the greater the cost of equity. At the same time, the decreased equity increases the likelihood that the equity will not be able to absorb the effects of adverse events and that debt payments would be in jeopardy. Hence, the lower the equity contribution, the higher the cost of debt.

Regardless of how the risks are spread over equity and debt investments, it is the risk of the operation that drives the cost of capital.

Q: Are the costs of capital for OPG's nuclear operations and its hydroelectric operations equivalent to one another?

A: No. OPG's nuclear operations are riskier than its hydroelectric operations. This point is made very clearly by OPG's witness, Kathleen C. McShane, in Exhibit C1-T1-S1. She makes the following points:

- The "risk to the nuclear operations that there will be unutilized baseload capacity will rise as additional low marginal cost generation becomes available. This is particularly problematic for nuclear generation, given the time required for the plants to ramp production up and down" (at pp. 68–69).
- "The production/operating risks related to the nuclear assets are significantly higher than those of the hydroelectric generation facilities (and are higher than those of any other types of generation). Nuclear technology is more complex than other types of generation and is subject to higher risks of unanticipated costs of repair and loss of production" (at p. 69).

- "Nuclear generating assets have significant operational and technology risks. OPG operates 10 of its 12 CANDU nuclear units at its three stations. Technical challenges associated with key components of the facilities have the potential to expose the nuclear units to lengthy outages and have negatively affected operational and cash flow performance in the past" (at p. 69, note 73).[1]
- "The nuclear operating environment is much harsher than for fossil generation or for hydroelectric generation. As a result, the complexity and length of time for repair of nuclear plants often exceed those of hydroelectric or fossil generation" (at p. 69).
- "The nuclear plants may also experience deterioration or shift in physical properties that go beyond what was expected or assumed in the design of the plant" (at p. 69).
- "The specific circumstances of OPG entail additional risk, as the reactors reflect different stages of the CANDU design. Ongoing updates to nuclear operating standards and regulations may require modifications to the plants, particularly those with older design reactors, to ensure compliance" (at p. 70).
- The "operating environment and the technological characteristics of OPG's nuclear generation fleet are such that the extent of required maintenance, repair or refurbishment is 1) forecast with a higher degree of uncertainty than for other types of generation, 2) can result in materially longer than anticipated outages and more frequent and longer than could be expected forced outages, 3) can result in higher than anticipated costs of repair or

[1]Ms. McShane was quoting "Summary: Ontario Power Generation, Inc." Standard & Poor's, April 24, 2007.

remediation, and 4) potentially lead to permanent loss of production either as a result of derating or a premature end of the economic life of the plant" (at p. 70).

- Standard & Poor's "finds that 'Exposure to outages and their attendant costs is often exacerbated because nuclear outages tend to be lengthy relative to outages at other types of generation units given the complexity of nuclear reactors and the safety and regulatory issues that must be addressed before a nuclear unit is returned to service'" (at p. 70, note 74).[2]
- "Other production-related risks to nuclear production include weather damage and the threat of increased algae runs (which restrict cooling water intake flows). With respect to the latter, algae runs become more problematic as average temperatures rise over time. Further, as average temperatures rise, it becomes more difficult to cool the reactors. Thus, nuclear stations are more significantly affected by external conditions (e.g., cooling water availability) than fossil plants" (at p. 70).
- Ontario Power Generation "faces significant risk of lost revenues due to longer and more frequent than anticipated outages and higher than expected costs to maintain and repair existing nuclear facilities" (at p. 71).
- Ontario Power Generation "may incur significant operating and capital costs (as well as face curtailment of production and potentially permanent shutdown) to comply with such CNSC regulations and license conditions." (at p. 71).
- "Regarding environmental requirements, particularly with respect to discharges to the environment, and handling, use, storage, disposal and clean-

[2]Quoting "S&P Seeks Improved Risk—Assessment Metrics for U.S. Nuclear Power" Standard & Poor's, December 20 2005.

up of hazardous substances, as well as the decommissioning of nuclear stations at the end of their useful lives, OPG also faces significant operating and capital costs" (at p. 72).

- "To the extent that nuclear production is adversely impacted by changes in legislation or regulations related to CNSC compliance or compliance with any other applicable laws, OPG is at risk" (at p. 72).
- "Both availability and cost of nuclear-skilled employees are a concern, as the retirement of a large percentage of the skilled workforce becomes increasingly imminent. Bruce Power competes for available skilled personnel; training cycles are lengthy and costly" (at p. 71).
- Market prices for uranium increased almost 200% over the period 2004-2006 due to a shortage in worldwide mine production and a drawdown of inventor....[from] under $20 per pound in 2004 to over $70 per pound at the end of 2006.[3] Since the beginning of 2007, market prices have continued to show high volatility with world prices reaching as high as $136 per pound (U.S.) from a low of $75 per pound (U.S.). Delays in bringing on new production could lead to even higher market prices. In addition, OPG's exposure to market prices for future years has increased due to a larger proportion of supply contracts that contain pricing indexed to market indicators at the time of delivery…. For example, over 50% of the deliveries in 2009 are priced based on world prices at the time of delivery…. Higher uranium prices have already increased OPG forecast fuel expense in 2009 by almost 140% relative to 2004; continued increases in uranium prices could push the fuel expense even higher" (at pp. 72–73).

[3] I believe that is a 250% increase.

- “With respect to decommissioning and used fuel risks, …a significant increase in the estimate of the liability could have a significant negative impact on OPG’s financial condition” (at pp. 73–4).
- “With respect to waste storage, although an options study for the disposal of high level waste has been submitted to the federal government, the choice of alternative could have a significant impact on the estimated liability. Risks associated with nuclear waste storage include financial impacts of sitting the geological repository and concerns in communities of interest. Licensing of the repository requires community support, which could deteriorate and result in protracted and costly processes. Similar issues exist with respect to the storage of low and intermediate level waste. The government has recently elevated the environmental assessment of OPG’s proposed deep geological depository within the Bruce Nuclear site to a panel, which could result in material schedule delays and costs” (at p. 74).
- Life extension “increases liabilities related to used fuel and waste management costs” (at p. 75).
- “In addition, since the assumption underlying decommissioning is that the reactors will be in safe storage for 30 years after the end of their useful life, and that dismantlement will take a further 10 years, there is a significant risk that the costs to service the liability will have changed, the decommissioning funds will not perform as was expected, and if they do not, that there will be no viable means to recover the deficit through regulated operations” (at p. 75).

Q: Are the higher risks of nuclear operations reflected in OPG’s rate proposal?

A: Yes. These risks are the basis for the following provisions in OPG's proposal, Exhibit C2-T1-S1:

- the proposal to collect 25% of nuclear costs through a fixed charge,
- "the proviso that it retains the right to request a deferral account to recover [nuclear-regulation] related costs if they result in a material financial impact" (at p. 72).
- the request for "a variance account to record variances between forecast and actual uranium costs" (at p. 73).
- the retention of the ability to seek deferral for future recovery of "unanticipated costs [that] are incurred due to unforeseen [nuclear] technological changes" (at p. 75).
- the retention of the variance account for decommissioning and used fuel costs.

Q: Do these OPG's proposals reduce the risks of nuclear investment?

A: No. They simply transfer the risks to OPG's customers and Ontario consumers.

Q: Should OPG's return be reduced to reflect the transfer of risks to consumers?

A: No. When the risks of an investor-owned utility are shifted to ratepayers, the utility's return should generally be reduced. But for OPG, as a provincial entity, a return on equity that reflects the underlying risks has two advantages. First, the higher return will increase OPG's retained earnings when all goes well, allowing OPG to absorb more of the costs of adverse outcomes when they occur. Second, since OPG will use the return set by the OEB in evaluating investments, it is important that the return on nuclear investments include as much of the nuclear risks as feasible.

Q: Do you believe that Ms. McShane's estimate of the cost of capital for OPG's hydro operations is reasonable?

A: While I have not attempted to independently verify Ms. McShane's estimate, it seems reasonable. Ms. McShane's estimated cost of capital for OPG's hydro operations is about 8%, which is similar to the costs of capital embedded in the bids in the current procurement of peaking capacity under cost-of-service contracts conducted by the Connecticut Department of Public Utility Control (Docket No. 08-01-01). Bidders were allowed to offer costs of equity up to 10.75%, indexed to allowed utility ROE (but with a 9.75% floor), and up to 60% equity. Bidders offered ROEs from 9.75% to 10.75%, and equity of 40% to 50%. With a 6% debt cost, these bids are equivalent to 7.8% to 9.1% overall return. The bids that have been recommended by experts for the Department and the Office of Consumer Counsel (including me) offered returns equivalent to 8.2% to 8.6%.

Q: How much greater might the cost of capital be for nuclear investments than for hydroelectric investments?

A: There are several distinct nuclear risks. Ms. McShane separately quantifies the cost of one risk—of variation in energy production—in estimating the effect on cost of capital of OPG's proposal to recover 25% of its nuclear revenues through a fixed charge. In Exhibit L-T12-S1, she estimates that "If the Board does not approve" that proposal "the increase in the required ROE could be approximately...25 basis points." If bearing 25% of the nuclear revenue risk requires 25 basis points, the entire nuclear revenue risk would be about 100 basis points, or a full 1% increase in ROE. Since nuclear represents only 45% of OPG's investment, Ms. McShane's quantification of the output risk over the next two years would require a 222-basis-point increase in the return on equity for the nuclear operations alone, or (for a capital structure with 57.5% equity) 128 basis points on overall return for the nuclear operations compared to operations without output risks. The 25% fixed-cost recovery would reduce the cost of capital for nuclear investment by 32 basis points.

Ms. McShane (Exhibit L-T12-S1) also estimates that a nuclear-only operation, with the fixed-charge proposal, but exposed to other risks, would require a combination of higher equity returns and/or more equity in the capital structure, as about 70% equity at the base 10.75% ROE or 60% equity at 11.25% ROE. Either of these estimates, with a 6% debt cost, would result in a 9.15% overall return, 56 basis points more than the return with OPG's requested capital structure and ROE.

Q: Are these two factors additive?

A: Yes, as Ms. McShane acknowledges in Exhibit L-T12-S1. The resulting nuclear cost of capital would thus be about 32 basis points more than the return requested by OPG, or roughly 9.5 %.

Q: Are you endorsing Ms. McShane's estimate of the nuclear risks?

A: No. I believe that she may be understating the risk of nuclear investments by assuming that consumers would cover large parts of the risks.

The nuclear cost of capital I compute from Ms. McShane's estimates is about 100 basis points greater than that for the Connecticut peaking plants. This small differential is plausible only to the extent that ratepayers remain at risk for all prudent costs, including long-term outages and early retirement. The full risk of nuclear investment to OPG and consumers is almost certainly greater than the 9.5% regulated-nuclear cost.

Q: Have you estimated the cost of capital for an enterprise fully exposed to the risk of owning and operating nuclear capacity?

A: I have not undertaken the significant effort required to produce a full independent estimate of the costs associated with bearing all nuclear risks. I understand that other parties in this proceeding have retained experts for this purpose. My testimony is limited to the issue of whether applying separate costs of capital for nuclear and hydro investments would be appropriate, and whether the difference in those costs would be significant, based on the evidence that OPG has provided.

Q: Are you aware of any other estimates of the costs of capital for nuclear ownership and operations?

A: Yes. In its review of the Bruce Power Refurbishment Implementation Agreement, CIBC World Markets found that a reasonable capital structure for Bruce Power would be 20–40% debt, with the remainder of its capital from equity with a 13.7%–18% return.[4] With a 6.2% cost of debt, CIBC estimates that this range of capital structure and return on equity would result in an overall cost of capital of 10.6% to 13.8%.

I cannot quite reproduce these results from CIBC's assumptions. I get the following average costs of capitals for the combinations of CIBC's assumptions:

	Debt as Percent of Capital	
Return on Equity	*20%*	*40%*
13.7%	12.2%	10.7%
18.0%	15.6%	13.3%

These results would not change much with the 6% cost of debt I have assumed for OPA. While the Bruce Power agreement would still result in some risks being shared with ratepayers, it is a closer approximation of an entity bearing the full risk of nuclear investment.

[4] Unsigned letter from CIBC World Markets to the Ontario Ministry of Energy (James Gillis, Deputy Minister and Rosalyn Lawrence, Director), October 17 2005.

IV. Importance of Differentiating Nuclear and Hydro Costs

Q: Why is it useful to distinguish the costs of capital for nuclear and hydro investments?

A: There are at least two benefits of separate costs of capital for OPG's two lines of business. First, if the OEB establishes separate costs of capital and the mix of OPG's investment changes, due to nuclear retrofits or refurbishment or new nuclear or hydro capacity, OPG's average allowed return would automatically shift in the direction of the investment mix. The return would only need to be updated for changes in market rates or the underlying risk in either OPG business segment.

Second, when OPG is reviewing options for capital investments—capital to reduce operating cost, capital to increase output, capital to extend operating lives—it's analysis should reflect the different costs of capital for nuclear and hydro investments.

Q: How might the different costs of capital for nuclear and hydro investments affect decisions about investments?

A: The higher the cost of capital, the higher the annual cost of capital investments and the lower the present value of future benefits.

For example, consider an $12 million investment that is expected to save $1 million (or add $1 million in revenues) in the first year, rising with 2.5% inflation for 20 years. Discounting at an 8% hydro cost of capital, the present value of the benefits is $12.4 million, suggesting that the investment is prudent and should be undertaken. Discounting at an 9.5% nuclear cost of capital, the present value of the benefits is $11.1 million, suggesting that the investment would not be prudent and should be rejected.

Equivalently, the first-year real-levelized carrying cost of the investment would be about $0.9 million with hydro financing and $1.1 million with nuclear financing, reflecting the higher risk of nuclear investments.

Q: Is it appropriate to use different costs in evaluating nuclear and hydro investments?

A: Yes. Just as the capital investments, fixed O&M costs, variable O&M costs, fuel and capacity factors vary between hydro and nuclear production (and even among plants in either segment), so does the cost of capital. It is no more reasonable to use a blended cost of capital for evaluating an investment than it would be to use a blended construction cost per kilowatt or fixed O&M per kilowatt-year.

Q: Does OPG use the cost of capital in evaluating investments?

A: Yes.

> To date, OPG has assumed a discount rate of approximately 7 percent, based on 10 percent ROE, 55 percent debt ratio and 6 percent cost of debt in the assessment of new investments.… In future assessments, OPG will consider the approved regulated ROE/capital structure along with OPG's cost of long term borrowings and make a determination of the appropriate discount rate to be applied. (Exhibit L-T3-S2(d))

Q: Does OPG acknowledge the importance of properly reflecting risk in investment decisions?

A: Yes. OPG acknowledges, "If different businesses or technologies are of different risks, it is important to account for that difference in risks appropriately in the financial analysis used to evaluate investments in these businesses" (Exhibit L-T3-S2(e)).

Q: Does OPG believe that the risk must be incorporated in the cost of capital?

A: No. OPG asserts, "The mechanism to account for difference in risks does not have to be through the use of a different cost of capital; it can be done by building risk into the cash flows in the analyse." (Exhibit L-T3-S2(e)).

Q: Can "building risk into cash flows" substitute for risk-adjusted cost of capital?

A: In principle, revenues from a potential investment could be reduced and operating costs increased to reflect the risks. In practice, it is difficult to capture the many risks of a complex business segment in this fashion. Some risks result from small probabilities of large increases in cost components that are expected to be small, while other risks reflect smooth distributions around the best estimate of a cost.

If the approach that OPG suggests were easy or straightforward, it could have simply adjusted each of its nuclear cost and revenue computations in its application to the risk-adjusted equivalent, and requested the hydro-equivalent return of about 8% for all its investments. I do not know whether OPG could perform (and explain) those analyses, but I suspect that it was wise to reflect nuclear risk in it requested return, rather than attempting to model risk-adjusted cash flows.

Q: Does this conclude your testimony?

A: Yes.