Docket BRD-E-R-10

NOVA SCOTIA UTILITY AND REVIEW BOARD

In the Matter of: The Electricity Act and a hearing to determine Renewable Energy Community Based Feed-in Tariffs

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE CONSUMER ADVOCATE

Resource Insight, Inc.

MARCH 17, 2011

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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 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 electric generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than 250 times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty states and five Canadian provinces, and two U.S. Federal agencies. This testimony has included the review of many utility-proposed power plants and purchased-power contracts.

Q: Have you testified previously regarding rates for utility purchases from non-utility generators?

A: Yes. I have testified in at least nineteen proceedings on non-utility purchase rates, including the following:

- Massachusetts DUP 19494 Phase II (1979), on co-generation rates.
- Massachusetts DUP 535 (1981), on generic rules for setting rates for quailfying facilities (renewables and cogenerators).
- Massachusetts DUP 84-276, on contract rates for qualifying facilities.
- Massachusetts DUP 88-19, on rates for power sales from a cogenerator to Western Massachusetts Electric.
- Massachusetts DUP 88-123, on Western Massachusetts Electric avoided costs.
- Massachusetts DUP 89-239, estimation of externality values in supply planning and procurements.
- Massachusetts DUP 89-141, 90-73, 90-141, 90-194, and 90-270, on the treatment of externality values in purchases from non-utility generators.

- Massachusetts DUP 91-131, updating externality values.
- Ontario Environmental Assessment Board Ontario Hydro Demand/Supply Plan Hearings (1992), on environmental externalities.
- Texas PUC 110000 (1992); on the environmental effects of a purchase of cogenerator energy by Houston Lighting and Power.
- Maryland PSC 8473 (1992), on evaluating Baltimore Gas and Electric's power purchase from AES Northside.
- Maryland PSC 8179 (1993), on Potomac Edison's proposed purchase from the AES Warrior Run coal-fired cogenerator.
- New Jersey BRC EM92030359 (1994), on the environmental costs of a proposed cogenerator.
- North Carolina Utilities Commission E-100 (1995), Sub 74, Duke Power and Carolina Power & Light avoided costs for small hydro facilities.
- Connecticut DUPC 05-07-18, on the financial effect of long-term power contracts.
- Connecticut DUPC 07-04-24, reviewing capacity contracts with non-utility projects.
- Connecticut DUPC 08-01-01, reviewing proposed peaking generation projects.
- Ontario EB-2007-0707, on the Ontario Power Authority integrated system plan, including the valuation of renewable energy supplies.
- Nova Scotia UARB P-172, on the proposed NewPage Pt. Hawkesbury biomass project.

Q: Have you previously testified before this Board?

A: Yes. I testified in the Board's review of the following cases:

- Nova Scotia Power's Demand Side Management Plan for 2010 and Demand Side Management Cost Recovery Rider in May 2009,
- the proposed purchased-power agreement between Nova Scotia Power Inc. ("NSPI") and a biomass project to be constructed at the NewPage Pt. Hawkesbury ("NPPH") pulp and paper mill (NSUARB P-172),
- Nova Scotia Power's proposal to build the biomass project at NPPH (NSUARB P-128.10),
- Heritage Gas's 2010 rate case (NSUARB NG-HG-R-10).
- Nova Scotia Power's proposal to increase production depreciation rates (NSUARB NSPI-P-891).

II. Introduction

Q: On whose behalf are you testifying?

A: My testimony is sponsored by the Nova Scotia Consumer Advocate.

Q: What is the purpose of your testimony?

A: I review the basis for the draft tariffs for Community Feed-In Tariffs (COMFITs) developed by the Synapse Energy Economics team and summarized in Exhibit B-1. In particular, I question the way in which Synapse incorporated, or failed to incorporate, the concept of "community" in estimating the cost of COMFIT projects. In addition, I compare Synapse's estimate of the cost of large COMFIT wind projects with the prices of similar-size market-based wind projects bid in response to NSPI's requests for proposals for renewable-energy projects.[1]

[1] Large COMFIT wind projects are in the same size range as the small wind projects NSPI has contracted for through the 2008 RFP and similar mechanisms.

Finally, I compute the rate effects of the proposed COMFIT tariffs, under a range of possible levels of COMFIT development.

Q: Please summarize your review of the Synapse proposal.

A: I have two major complaints about the Synapse report, and a few minor points. The first major point is that Synapse did not interpret its charge from the Board to include such important issues as the amount of capacity that might be developed under the tariffs or the resulting rate effects. As I result, I have performed my own analysis of potential rate effects. As discussed in Section VIII, I find that a vigorous COMFIT program at the rates proposed by Synapse could result in substantial rate increases.

My second major concern, discussed in Section IV, is that Synapse interpreted the concept of "community" to exclude any real community support for the projects and assumed that community ownership could only be a detriment to project development. Consequently, Synapse overstates financing and other costs of community projects. Synapse's failure to recognize the benefits of community ownership and support also seems to account for Synapse's failure to recognize the large gulf between proposed large-wind price and the prices NSPI is paying for energy from comparable-size wind projects under competitively-sourced contracts, or between Synapse's proposed rates and those in effect in other jurisdictions, as I discuss in Section VII.

With a handful of exceptions, Synapse's analysis generally appears to be technically competent. The inputs generally appear to be reasonable, to the extent that single input values can be representative of such varied situations as small hydro and biogas cogeneration, and for the still-developmental in-stream tidal technologies. Nonetheless the Board should be concerned about the following problems:

- an error in computation of the biomass rate, which I discuss in Section III.
- the capacity factor for large wind, which I discuss in Section IV.
- the assumptions related to community support (wind and hydro financing, property taxes, and development costs), which I discuss in Section V.

Q: What rates do you recommend for the COMFIT technology categories?

A: As I explain in Section IX, I recommend the COMFIT rates shown in Table 1, based on combining the effects of the following adjustments and considerations:

- a corrected biomass formula,
- a realistic capacity factor for the large wind projects,
- lower-cost capital for wind and hydro due to community support,
- property-tax relief for hydro projects,
- reduced development costs for community-supported projects,
- lower expected return for demonstration tidal projects.

Table 1: Comparison of Synapse-Proposed and Recommended COMFIT Rates
(Dollars per MWh)

	Synapse Proposal		Recommendation	
Technology	Fixed	2012 Variable	Fixed	2012 Variable
Small Wind	$452		$400	
Large Wind	$139		$102	
Biomass CHP	$94	$62	$94	$56
Hydro	$140		$114	
Tidal	$652		$381	

Q: What restrictions should be placed on the COMFIT rates when tariff sheets are prepared?

A: I suggest two such restrictions. First, it should be clear that no project will be eligible for COMFIT if it might result in power flowing backwards in the distribution substation, from the distribution side of the transformer to the transmission side. Second, the total capacity on the tidal COMFIT rate should be limited to minimize the effect on customer bills. I propose a limit of 3.5 MW, which would be sufficient for several demonstration projects and would limit the total rate effect to be similar to the small wind category, which is limited by regulation to 5 MW total.

III. Error in Biomass Computation

Q: What error did you find in Synapse's computation of the biomass rate?

A: Even given all of Synapse's assumptions, I believe that the recommended rate is too high. Synapse computed a levelized rate that would produce Synapse's intended 13% return cover all fixed costs and the escalating fuel and O&M costs. In other words, the $156/MWh is not the starting point for escalation. It is the appropriate price for the contract term, if fuel prices rise at 1.92%, along with O&M.

Synapse then proposes to escalate the levelized fuel price of $62/MWh at its recommended fuel escalator: 75% of 90% of CPI inflation (excluding energy) and 25% of diesel inflation. Instead, Synapse should have proposed to escalate the first-year fuel cost ($55.6/MWh).

The first-year price (again, using Synapse's input assumptions) should be $149.5/MWh, with $93.9/MWh subject to escalation and $55.6/MWh fixed.

Q: How much might the Board expect the proposed fuel escalator to rise over time?

A: In the 2010 Annual Energy Outlook (AEO 2010), the U.S. Energy Information Administration projects an average real escalation rate of 1.67% for commercial distillate, from 2012 through 2032. Combined with the 1.92% general inflation rate used in the Synapse analysis, diesel would rise at 3.63% nominal, assuming AEO 2010 is correct and that Canadian prices track U.S. prices. Weighting the diesel escalator 25% and the general inflation rate 75% produces a forecast biomass inflation rate of 2.2%.

In this case, the Synapse proposal would, inadvertently, apply an effective fuel escalation rate of about 4.2%.

IV. Large COMFIT Wind Capacity Factor

Q: What capacity factor underlies Synapse's proposed rate for wind projects over 50 kW?

A: Synapse uses 31%, which is the average of a 30% value suggested by wind developers (apparently without any documentary support) and a 32% value taken from the Hatch report (2008).[2] Synapse notes that Hatch reported that "capacity factors in four of the six zones studied range from 31% to 35%, and that in two zones the capacity factors are higher" (but strangely fails to note that the higher capacity factors are nearly 44%), and describes the Hatch estimate as "conservative."

Q: Is Synapse correct in its characterization of the Hatch report?

A: I think not. While Synapse claims "Hatch conservatively uses a capacity factor of 32% for their energy estimates," Synapse does not specify where in the 200-page Hatch report it found the 32% capacity factor value.[3] The range of capacity factors that Synapse cites are from Hatch's Table 4-2, which reports annual capacity factors as follow:

[2]Hatch, Nova Scotia Wind Integration Study, prepared for the Nova Scotia Department of Energy, 2008.

[3]I cannot find any reference to the term "conservative" in the Hatch report, so that characterization is apparently Synapse's opinion, rather than Hatch's.

- West: 33.35%
- Valley: 34.59%
- Truro: 31.86%
- Pictou: 31.86%
- Canso Strait: 43.59%
- Sydney: 43.59%

Hatch's Table 4-3 shows Hatch's estimates of capacity factors of various levels of future wind power. It applies those zonal capacity factors and finds average capacity factors for future wind resources varying from 33.4% for the lowest penetration scenario (311 MW, essentially the level now under contract) with development concentrated toward Pictou and Truro, to 36.71% with 961 MW of wind and development concentrated toward the Valley zone.

The only reference to a 32% capacity factor I can find in the Hatch report is in Chapter 3, involving the firm capacity credit for wind. Hatch does state ([. 3-4) that "the firm capacity of the future wind plants was calculated based on a presumption of 32% annual capacity factor." In fact, Hatch used 32% as the ratio of firm capacity to nominal capacity, so this may be a typographical error.[4]

In any case, when Hatch computed average capacity factors, it derived values greater than 32%.

Q: What is "conservative" about selecting a capacity factor biased to the low end of the range?

A: Nothing, from a public-interest perspective. In engineering, a "conservative" estimate is one that is intentionally biased in the direction that provides a margin of safety, such as understating the strength of materials or overstating the likely

[4]Indeed, on page 2-1, Hatch refers to "the presumption of 32% firm capacity contribution."

number of dancers in a ballroom. Selecting a low estimate of capacity factor does not protect consumers; it unnecessarily increases prices.

The only sense in which this particular decision could be considered to be conservative (as Synapse uses that term on page 21, lines 31–32, of Exhibit B-1) would be from the perspective of developers.[5]

Q: What would be a realistic estimate of capacity factor for large COMFIT wind projects?

A: For the distribution-connected wind plants installed after 2007, NSPI's reported energy output forecasts imply capacity factors that average 37%. Only two of the eleven plants are expected to have capacity factors smaller than Synapse's 31% estimate.

Interestingly, the eleven earlier (2005–2007) small wind units owned by or selling to NSPI have an average capacity factor of 26%. Developers seem to be getting better at identifying good wind sites.

Q: How much lower would the COMFIT rate be with the 37% average capacity factor, rather than Synapse's intentionally understated 31%?

A: Substituting the 37% capacity factor into the Synapse spreadsheet reduces the required COMFIT rate for a taxable owner from $142/MWh to $119/MWh, and for a non-taxable owner from $136/MWh to $114/MWh; the average required rate would fall from $139/MWh to $117/MWh.

[5] On page 23, line 7, of B-1, Synapse uses "conservative" to describe Hatch's choice of a low capacity factor to lean in the direction of understating energy output; in that very different application, the low capacity-factor assumption would protect the Province from overstating wind-energy potential.

V. Benefits of Community Support for Renewable Power Projects

Q: How does the Synapse team view the effect of community involvement in development of COMFIT projects?

A: Synapse assumes that community involvement adds to the costs of project development, and ignores almost all the benefits of community-based development. Synapse accepts that community-based ownership requires more debt than commercial projects (Exhibit B-1, p. 12). Synapse also asserts that majority ownership by a community-based group requires that COMFIT rates be higher than FIT rates in Vermont, for small wind (Exhibit B-1, p. 20), large wind (p. 23), biomass (p. 27), and hydro (p. 32).[6]

In the following places in Exhibit B-1, Synapse essentially assumes that the COMFIT investors would be motivated and behave exactly like investors in capital markets:

- Synapse bases interest rates on debt entirely on the rates that commercial lenders suggested they would require for financing COMFIT projects (p. 12).
- Synapse assumes that the cost of capital will be higher for COMFIT projects because "investors who buy utility stocks rely on the utility's diversified portfolio of resources…[while] most investors in organizations developing a COMFIT project would be investing, at least initially, in one project" (p. 15).

[6]Synapse's position that community ownership burdens COMFIT biomass projects is curious, since the project can be majority owned by the steam host (e.g., a sawmill) and the minority owned by anyone. Indeed, any COMFIT project can be owned up to 49.9%, and managed, by any party, including the parties Synapse expects to own small FIT projects in Ontario and Vermont.

- “For projects owned by community-based groups, investors are likely to see project size risk, portfolio risk and, for some community-based groups, risk due to inexperience” (p. 15).
- “In the case of projects developed by municipalities and universities, investors are likely to perceive less risk due to inexperience with energy projects, or perhaps even none” (p. 15).
- “In the case of a new non-profit or CEDIF or a first energy project by a First Nation, investors are likely to see significant risk due to inexperience” (p. 15).
- “If tidal developers put up their own equity, we believe they should receive a return well above the NSPI rate for taking on these risks, and if developers seek outside equity, they will probably have to show very high expected returns relative to NSPI to attract capital” (p. 16).

None of these passages describes the purposes, decision-making, or return requirements for community members or institutions in renewable energy projects. Indeed, many of these passages ignore entirely community ownership, or assume that community investors are indistinguishable from private equity funds or investment banks.

Synapse concludes that the 13% return on equity allowed for Heritage Gas is a reasonable target for most COMFIT resources. Heritage Gas was funded by Alberta’s AltaGas, as a straightforward investment to generate profits, without any social, environmental or community concern. Heritage Gas is essentially the polar opposite of a community renewable project.

Synapse also assumes that, despite the nominal designation as a community renewable project, these renewable plants would receive no material support from the local community and would be assessed property taxes like any commercial enterprise.

Q: What benefits would a community renewable project have, compared to a commercial development?

A: A truly community-based project would benefit from municipal, university or community financing; the donation of land and services; and property tax relief.

Q: How would the financing of a community project differ from financing of a purely commercial enterprise?

A: A truly community-based project would expect financial support from the community. That may be in the form of donations or low-cost financing from some combination of the local government, the citizenry, and local institutions.

Synapse assumes that no one will invest in community renewable projects unless they are promised returns commensurate with returns available from corporate stocks and bonds of equivalent risk. Since Synapse assumes that community projects are very risky, the assumed returns are 8% of debt and 13% on equity, with 15% return on equity required for tidal plants.

Contrary to Synapse's assumption, municipalities can and do raise debt capital at less than 6%, and there is no reason to suppose that they could not do so for a municipally financed renewable project. Universities generally finance capital projects, especially projects that are highly visible and well regarded, through donations from alumni, wealthy individuals, and corporations.

As for local individuals and institutions, they frequently donate money to support causes they believe in, earning a direct financial return of -100% (or something a little less negative if the donation is offset by an income-tax deduction). This is how construction of community centers and libraries are typically funded, with a combination of individual and corporate contributions and local government support. Certainly, a supportive community will invest in a project at returns lower than full market rates, but higher than rates available to small investors. If they are unwilling to do so, the project clearly does not have community support, and is simply a commercial project.

Q: Are you familiar with the financing of community energy projects?

A: Yes. In Massachusetts, a program was established under which a state agency matched funding from local contributors to install panels on school buildings. I personally contributed to two rounds of project funding in my home town, Lexington; the response to the public appeal for the first array was so enthusiastic that the sponsors decided to fund a second array. Eleven other communities also raised enough money to participate in this or similar programs and install panels.

Many of the people who contributed tens or hundreds of dollars could equally well have invested thousands of dollars if they were likely to get their money back, especially with a return comparable to what they would otherwise earn.

Other examples of community financing of renewable energy projects include:

- The Sakai Intermediate School in Bainbridge Island, Washington, raised \$30,000 in contributions to purchase and install solar panels.
- The Clean Energy Collective of El Jebel, Colorado, organized about 20 members to purchase solar panels at \$3,150/kW (after all rebates and tax credits), with the power to be sold to the local utility at 11¢/kWh. Assuming an 18% capacity factor and no maintenance costs, the internal rate of return for the owners is 1% if the panels last 20 years and 3% if the panels last 25 years.
- The Appalachian Institute for Renewable Energy installed a PV system financed by seven to 10 individuals, who paid \$1,700/kW (after incentives)

and sell energy to AIRE at under 10¢/kWh. At a capacity factor is 17%, with no escalation in the sales price, the IRR would be 7%–8%; with 2% escalation, the IRR would be 9–11%.

Q: What return can consumers earn on standard fixed-income investments?

A: Currently, some Canadian banks are offering 5-year GICs at 2% interest rates. At least one on-line bank, ING, offers 3% interest on a 5-year GIC.

Q: What returns would you expect to be required to attract capital from community members?

A: If community members are not willing to invest in the project at interest rates of 5% or 6%, or expected equity returns of 10% or 11%, they must not be very interested in the project. As one of the parties advocating for COMFIT investments said in an email to the service list in this proceeding,

> Economically speaking, individuals have savings that they invest in interest-earning activities. Those savings, if made available for clean energy generation, could really assist the revolution we need in our energy systems. (Janice Ashworth, email "Re: Full cost accounting: how renewables should be assessed!" to COMFIT parties, March 5, 2011)

Offering a 6% interest rate should certainly make available a large amount of savings, if local individuals are favorably disposed towards the project.

Q: What sort of in-kind donations would a community project generally expect?

A: Three types of in-kind donations seem likely. One important likely contribution to a community project would be donation of land and access, either by the local government or a community member or organization.

Eliminating the land lease expense assumed by Synapse would reduce the hydro rate by \$0.7/MWh, of large wind by about \$4/MWh, and tidal by \$2/MWh.

Second, community projects, such as construction of parks and playgrounds, often benefit from the use of the staff and equipment of the municipal public works department, such as for construction of access roads and delivery of construction materials. Local suppliers and contractors also often contribute labor, equipment and materials, either free or at cost.

For community renewables projects, major parts of the installation process are likely to be beyond the capabilities of local firms, but grading access roads, erecting utility poles and stringing conductor for the customer portion of the interconnection, fencing the construction area, and delivering and pouring concrete and gravel, may all be within the capability of public and local community organizations. The entire process of erecting a small wind turbine may be within those capabilities.

The amount of in-kind support will vary widely among projects, depending on local capabilities and the details of the project.

Third, local government and volunteers can substantially reduce development costs, by scouting sites, conducting economic feasibility studies, drafting incorporation documents and contracts, and by handling fundraising, licensing and permitting, and outreach to abutters and the community.

Cutting Synapse's estimate of development costs by 25% would reduce the revenue requirement for large wind by $5/MWh and tidal by $28/MWh. Synapse does not break out development costs for small wind and hydro.

Q: Why would a community project expect property-tax relief?

A: If the local town or municipality owns the project, it would not tax its project any more than it would tax its schools. Similarly, if local residents (and voters) are pursuing a renewable-energy project, waiving property tax is an easy way for local government to support the project without any expenditure of public funds.

Q: How much might that property-tax relief be worth?

A: The effective property tax rates are very low on all the technologies modeled by Synapse, except for hydro. For the Synapse hydro project, property-tax exemption would reduce the required COMFIT tariff by $14.5/MWh.

VI. The Cost of Capital for Tidal Projects

Q: What cost of capital did Synapse assume for tidal projects?

A: Synapse assumed 100% equity financing at 15% return on equity.

Q: Does this capital structure represent a community project?

A: No. Synapse's discussion of the financing of tidal projects makes it clear that the capital structure represents a market-based commercial venture.

Q: Would you expect any tidal projects connected to the Nova Scotia distribution system in the next few years to be commercial ventures?

A: No. Tidal power generation is in the development-and-demonstration phase. Technology manufacturers cannot expect to make competitive returns on the equipment they are currently installing. The payback on these early, limited-run (sometimes unique) models is in information and reputation, rather than revenues.

For example, Verdant has been demonstrating its tidal technology—now in its third generation of test turbines—at its Roosevelt Island in New York's East River. Verdant has been selling its power to a nearby supermarket and parking garage. While New York City electricity prices are higher, it is doubtful that Verdant is getting much more than $200/MWh for its power, compared to the

$652/MWh recommended by Synapse. Unless Synapse's estimate of the cost of building and running tidal plants is grossly overstated, Verdant would be lucky to be recovering its investment in its demonstration project, let alone earning a return.[7]

Q: What equity return might be appropriate for tidal projects in the COMFIT computation?

A: If the COMFIT includes a 6% after-tax equity return, it would be more than a tidal-equipment manufacturer could expect to earn on projects elsewhere. The resulting rate of about $398/MWh would still be about twice what Verdant received in New York, and about four times the rate that a demonstration tidal project would receive in British Columbia under the Standard Offer Program.

VII. Reality Checks

Q: How can the Board assess the reasonableness of the COMFIT rates proposed by Synapse?

A: The Board should compare the proposed COMFIT rates to rates in similar programs, especially if those programs have attracted applications from projects of the scale and technologies eligible for COMFIT. If projects have been proposed and built in other jurisdictions in response to a certain rate, that rate is also likely to support development of COMFIT projects in Nova Scotia, all else equal.

A second approach is to compare the proposed COMFIT rates to the prices offered in response to NSPI's past renewables RFPs. Unfortunately, this comparison is largely limited to projects comparable to the large COMFIT wind

[7] This is even before the environmental studies that Verdant undertook at Roosevelt Island to support the licensing process for future projects.

projects, which have been bid into the RFPs. This test is especially valuable since it applies directly to non-utility projects developed in Nova Scotia.

A third approach is to compare the proposed COMFIT rates to the cost of renewable projects developed by NSPI.

A. Comparison to Other Jurisdictions

Q: How do the proposed COMFIT rates compare to those in other jurisdictions?

A: Synapse's proposals are consistently priced higher than those in other jurisdictions, except for the large-wind rate, which is slightly lower than the Ontario rate.

Table 2 compares the Synapse-proposed rates to the biomass, hydro, and wind prices for small generators offered by the Ontario Feed-In Tariff (including the micro-FIT for projects under 10 kW), the British Columbia Hydro Standard Offer Program, and the Vermont SPEED program. Synapse's proposed rates are in 2012 dollars, while those for Ontario and British Columbia are in 2010 dollars and would inflate to the project start date. The BC rates do not vary by technology, but do vary by location.

In each category, BC Hydro will also pay up to $150/kW of interconnection costs, which is equivalent to several more dollars per MWh in tariff payment. Since the BC rates are much lower to start with, including the interconnection costs would still leave the BC prices well below those of the other jurisdictions.

Table 2: Comparison of Existing and Proposed FIT Rates

Technology and Size	Jurisdiction	Starting Price $/MWh	Percent of Price Escalating with Inflation	Levelized Price 2012$/MWh	Potential Community Adder
Biomass					
unknown	Nova Scotia (SEE)	$156	30% at 0.9×CPI 10% at diesel	$166	
≤ 10 MW	Ontario	$138	20% at CPI	$147	$4
≤ 15 MW[a]	British Columbia	$95–104		$99–$108	
≤ 2.2 MW	Vermont	$125	Levelized	$130	
Hydro					
unknown	Nova Scotia (SEE)	$140		$140	
≤ 10 MW	Ontario	$131	20% at CPI	$140	$5
≤ 15 MW	British Columbia	$95–104		$99–$108	
≤ 2.2 MW	Vermont	$123	Levelized	$128	
Small Wind					
≤ 50 kW	Nova Scotia (SEE)	$452		$452	
≤ 100 kW	Vermont	$215	Levelized	$223	
Larger Wind					
> 50 kW	Nova Scotia (SEE)	$139		$139	
All	Ontario	$135	20% at CPI	$144	$10
≤ 15 MW	British Columbia	$95–104		$99–$108	
> 100 kW < 2.2 MW	Vermont	$118	Levelized	$123	

Sources: Vermont prices from Vermont PSB, Docket 7533, 1/15/2010 Order, Attachment II. BC prices from "Standing Offer Program (SOP): SOP Changes and Process Review," February 23, 2011. Ontario prices from FIT Price Schedule, August 13, 2010. Aboriginal adder is 50% greater than community adder.

Notes
[a]The BC Standard Offer Program was limited to 10 MW installations until 2010.

Figure 1 and Figure 2 show these prices in levelized 2012 dollars. For the diesel part of the Synapse-proposed biomass fuel escalator, I added NSPI's 1.92% forecast of general inflation to the 1.7% real escalation rate forecast for 2012–2032 in the US Energy Information Administration's Annual Energy Outlook, to get 3.6% nominal inflation.

Figure 1: FIT Rates Excluding Small Wind

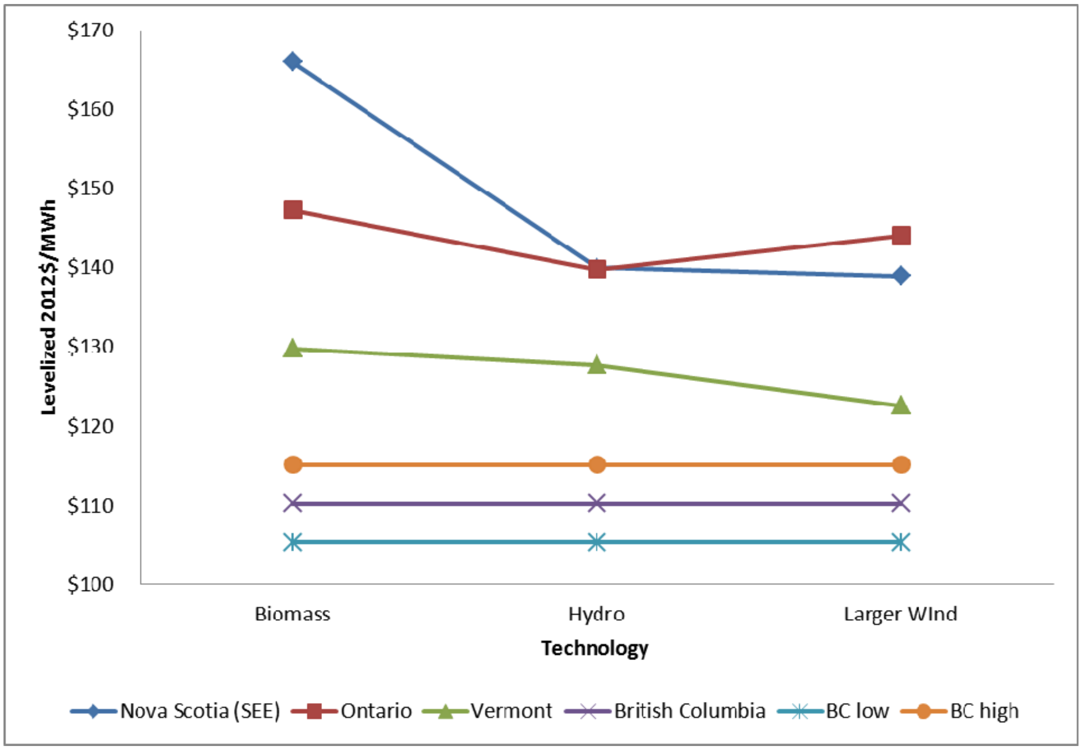
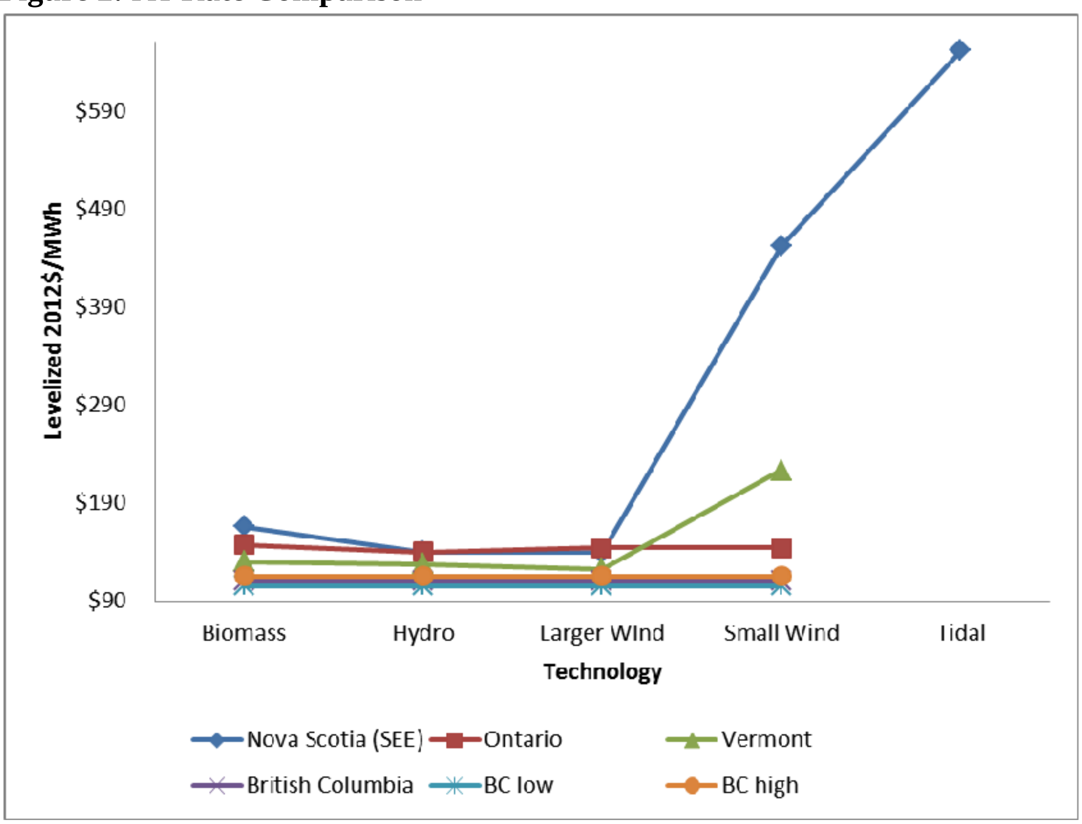


Figure 2: FIT Rate Comparison



Q: Have these lower prices led to offers from small renewable projects?

A: Yes. I have not been able to find any detail on the BC standard-offer projects. As of November 1, 2010, BC Hydro reports the following projects:[8]

- Five hydro projects averaging 7 MW under contract. One of these is Regional Power's 20-MW Bear Hydro Project, implying that the remaining projects average less than 4 MW.
- One biogas project of 1.3 MW under contract.
- Twelve pending hydro applications averaging 7 MW.
- One pending biomass application of 5 MW,
- One pending biogas application of 0.3 MW.

In contrast, Vermont identifies individual FIT projects. Applications have included the following projects:

- 9 biomass projects, ranging from 400 to 2,200 kW.
- 21 wind projects, ranging from 100 to 2,200 kW.
- 14 hydro projects, ranging from 50 to 2,200 kW

Some of these projects have since been withdrawn or downsized, perhaps due to interconnection constraints. More biomass projects might have been offered, but the first day's applications exceeded the 12.5 MW allowed for biomass projects. The initial oversubscription of the total 50 MW FIT cap may have also discouraged additional applications.

The Ontario Power Authority provides Bi-Weekly FIT and microFIT Reports that summarize the number and capacity of projects by technology and status. Unfortunately, the data on the distribution of project size are limited. The OPA reports do provide the number and capacity of projects by technology in the "allocation-exempt" group, which include distribution-connected units up to

[8] Standing Offer Program: Report on the SOP 2-Year Review, BC Hydro, January 2011, p. 2.

250 kW or 500 kW, depending on the distribution voltage, and the total number and capacity of applications under the micro-FIT, which is limited to projects up to 10 kW. Projects in all three categories (micro-FIT, allocation-exempt, and other) receive the same prices, but the approval process is simpler for the smaller projects.

On the micro-FIT, OPA reports about 26,000 applications and states that only about 1% are not solar projects. That leaves some 260 projects for the other technologies; most of these are likely to be very small wind turbines.

In the allocation-exempt group, OPA reports 5 biomass projects (two at 100 kW each and one at 300 kW), 7 hydro projects (totaling 1.6 MW), and 13 wind projects (totaling 3.2 MW).[9]

Above the "allocation-exempt" group, it is not generally possible to determine the size of individual projects, since OPA reports only the total number of units and total MW in each progress category. As of the February 18 2011 report, the three hydro units in the "submitted" category averaged about 2 MW apiece, and the one listed as "application complete" had a capacity of 1 MW. The nine projects withdrawn or rejected (perhaps due to transmission problems) averaged 2 MW. The 73 hydro projects awaiting connection approval or under contract averaged about 4.5 MW; some of them were likely to be small enough to connect to distribution, as well.

The average Ontario biomass and wind FIT projects are too large to connect to distribution; it is not clear how many small projects are lurking in the aggregated data. By tracking changes in status, I have identified a few examples. In the November 9 report, one hydro unit of about one MW submitted an application, while another unit of similar size moved to the "contract executed"

[9] I excluded projects that were listed as withdrawn or rejected.

category, and two wind projects totaling 3 MW applied. In the November 22 report, a 2 MW biomass unit failed the connection review.

B. Comparison to Nova Scotia Power's Procurement Results

Q: What NSPI RFP results can be used in testing the reasonableness of the Synapse-proposed COMFIT rates?

A: Eleven recent wind projects are under contract to NSPI, most from the 2008 RFP for distribution-connected renewables.

Table 3: Small Recent RFP Wind Plants

Project	MW	In-Service Date
Cape North	0.65	31-Dec-10
Spiddle Hill (distribution)	0.80	31-Dec-11
Watts Section, Sheet Harbour	1.50	31-Dec-10
Donkin Wind Farm	1.60	1-Jul-10
Granville Ferry Wind Power Project	2.00	31-Dec-10
Isle Madame Wind Power Project	2.00	31-Dec-10
Dunvegan Wind Power Project	2.00	31-Dec-10
Creignish Rear	2.00	31-Dec-11
S. Cape Mabou	2.00	31-Dec-11
Irish Mountain	2.00	31-Dec-11
Fairmont Wind Farm	4.00	1-Jun-12

Sources: Point Tupper Wind NSPI (Avon) IR-3 Attachment 1 and NSPI (CA) IR-3 Attachment 1; Fairmont Wind Farm website.

In the first table and figure in Confidential Exhibit PLC-2, I show the contract price for each of these projects, as well as the average price.

Q: Are any adjustments in these prices necessary before comparison to Synapse's proposed rates?

A: Yes. The bid prices for the 2010 projects can be presumed to be reduced by about $7.5/MWh, the levelized value of the ecoEnergy credits available for most renewable projects that enter service before March 2011. The developers of these units may have discounted the value of the ecoEnergy credits, since neither operation before March 2011 nor continued availability of the credits would have been certain at the time of their bid preparation. While I add back $7.5/MWh for the 2010 projects in Exhibit PLC-2, that may overstate this adjustment.

Second, the cost of turbines, towers, and installation has fallen since the 2008 peak, due to reduced demand for turbines and commodities and increased global manufacturing capacity. As Synapse observes, "We estimate that our project costs are roughly 11% lower than 2008 project costs, consistent with data showing falling turbine prices since that time" (Exhibit B-1, p. 22). As shown in Exhibit PLC-2, reducing the bid prices 10% just for the projects expected to enter service in 2010 more than offsets the loss of the ecoEnergy credits.

Third, offering a known feed-in tariff to all eligible facilities should reduce the risk of development, compared to preparing a proposal in response to an RFP, without any assurance that your project will be selected. This reduction in risk should translate into a reduction in price. I have not estimated this effect, but it is one more reason that my adjusted RFP prices may still be overstated compared to conditions facing COMFIT projects.

Fourth, these prices represent for-profit commercial financing, without the benefits of municipal or community financing, donation of land, or property tax relief.

The first two adjustments are reflected in the second table and figure in Exhibit PLC-2.

Q: Did you make any other adjustments?

A: Yes. As a sensitivity, I adjusted the projects with 2011 in-service dates for the reduction in input prices, as described above for 2010 projects. I cannot tell when these projects locked in their input prices. The results are shown in the third table and figure in Exhibit PLC-2.

Q: What do you conclude from these comparisons?

A: I have three observations. First, the $139/MWh proposed by Synapse for large COMFIT wind projects is much higher than the actual prices in the contracts for recent RFP wind projects of comparable-size units, and even further above those contract prices when they are adjusted to current conditions. The Synapse proposal would need to be reduced substantially (i.e., by well over 10%) to be consistent with the actual bids.[10]

Second, NSPI has rejected a number of projects, including some that would have connected to distribution, that offered prices lower than the Synapse proposal.

Third, no economies of scale are evident over the range of unit sizes for which we have data. While at least one commenter expressed concern that a price set for a 2 MW project might be inadequate to support a 600-kW project, the bid data indicate that costs are quite stable over this range.

C. Comparison to Nova Scotia Power's Wind-Project Costs

Q: What levelized costs have NSPI estimated for the wind projects it owns?

A: The company reports that the Nuttby project will cost $84.54/MWh (Nuttby Application, September 2009, p. 16) the Point Tupper Wind Project will cost

[10] Specific values are listed in Exhibit PLC-2.

$91.65/MWh (Point Tupper Application, February 23, 2010, p. 16), and that Digby will cost $86.71/MWh (Digby Application, July 23, 2010, p. 25). Even adding in $7.50/MWh for the loss of the ecoEnergy credit would leave these costs below $100/MWh; taking into account the decline in turbine prices, current costs for additional NSPI wind generation would be even lower.

VIII. Potential Rate Effects of COMFIT

Q: Please describe your analysis of the rate impacts from implementation of the COMFIT program.

A: I estimated the impact on the Company's system-average rate from the purchase of power from community-based renewable resources at the tariff rates proposed in Synapse's March 2, 2011 filing.[11] Specifically, I estimated the percentage amount by which the current system-average rate would increase in a representative year with purchases from a mix of small and large wind, biomass CHP, hydro, and tidal resources. My analysis accounted for both the increase in costs to the Company associated with COMFIT payments to eligible resources and the offsetting reduction in the Company's power-supply costs that would be avoided with purchases from COMFIT resources.

Q: How did you derive the current system-average rate?

A: I calculated the current system-average rate as total system revenues divided by total system sales. For both total system revenues and sales, I used the Company's forecasts for 2011 for the so-called "Above the Line" rate classes, as reported in the Company's December 10, 2010 Fuel Adjustment Mechanism

[11] I used Synapse's proposed tariff as filed, without corrections or adjustments.

compliance filing in Case No. P-887(2). Based on these forecasted amounts, I derived a system-average rate of $111.73/MWh.

Q: How did you estimate the change to the current system-average rate due to COMFIT projects?

A: I derived the rate impact from COMFIT purchases by estimating both the annual payments at COMFIT rates and the annual power-supply costs avoided with purchases from COMFIT resources.

I estimated total first-year COMFIT payments for the five cases listed in Table 4. In each case, I assume that the full five MW of small wind is subscribed, given the very high rate proposed. Case 1 includes only the small wind, to determine the effect of that component of the program. The other cases examine a mix of capacity and the following amounts for capacity are eligible for COMFIT payments. Cases 2–4 assume that COMFIT development will be limited to 100 MW, due to constraints on distribution capacity and the location of renewable resource potential.[12] Case 5 relaxes that assumption, assuming a total of 170 MW, which could result from any combination of the following:

- utilization of a higher percentage of available net minimum load,
- higher-than-forecast capacity factors (since an increase in capacity factor has the same effect on revenues as the same percentage increase in installed capacity),

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[12] Nova Scotia Power estimates that the sum of minimum loads on its substations, net of generation already installed on the feeders, is about 200 MW. Additional generation may be feasible on many feeders and substations, but if distribution-connected generation could exceed load, NSPI must analyze the effect of the back-flow on the transmission system. As I understand the situation, DOE does not intend to approve any COMFIT projects affecting the transmission system. Since not every substation serves areas well-suited for renewable project development, NSPI and DOE have assumed that only half the remaining substation capacity would be utilized.

- installation of controls on distributed generators to limit their output at minimum substation load.[13]

Table 4: COMFIT Cases (MW by Technology Group)

	Case Number				
	1	2	3	4	5
Description	Small Wind	Mostly Wind	Balanced	High Tidal	High Penetration
Small Wind	5	5	5	5	5
Large Wind		85	50	25	50
Biomass CHP		5	20	20	30
Hydro		4	20	20	35
Tidal		1	5	30	50
Total	5	100	100	100	170

I estimated total annual COMFIT payment for each case from Synapse's proposed rates and assumed capacity factors by resource types.

Q: What is your estimate for the offsetting reduction in other power costs associated with COMFIT purchases?

A: As with my calculation of COMFIT payments, I estimated annual generation from COMFIT resources based on my assumptions regarding eligible capacity and the capacity-factor assumptions provided in the Board Counsel's filing. I then derived three estimates of power-cost reductions using three different measures of the market value of COMFIT generation.

First, I estimated savings from COMFIT purchases assuming that such purchases would free up equivalent amounts of generation for sale in the export market. I valued those exports at NSPI's forecast for the average export price of $59.22/MWh, as reported in the December 10, 2010 Fuel Adjustment Mechanism compliance filing in Case No. P-887(2).

[13]This approach may be most feasible for biomass CHP, since minimum substation load will tend to coincide with times of inactivity for the host facility, such as early Sunday mornings.

Second, I valued COMFIT generation by assuming that such purchases would back down output from the Company's generation fleet, at the average cost of fuel. In principle, increased energy from renewable should back down the most expensive energy in each hour, but that may not be possible due to contract requirements and operating constraints. For the average price of fuel, I used the 2011 Base Cost of Fuel for the above-the-line rate classes of $46.12/MWh, as reported in the December 2, 2010 2011 Base Cost of Fuel compliance filing.

Finally, I valued COMFIT generation by assuming that such purchases would reduce the amount of renewable generation that NSPI would need to procure to comply with the Renewable Energy Standard. I assume that renewable purchases through RFPS would cost $110/MWh, roughly based on my analysis in Exhibit PLC-2.

I did not include any cost of integration of renewables. NSPI has assumed that integrating wind would cost $10/MWh (Port Hawkesbury Biomass Project Application, Appendix 8). That value is probably an over-estimate, but the value may not be zero, either. Any integration costs would increase the rate increases due to COMFIT wind that is not displacing other wind resources.

Q: Please summarize your findings regarding the net impact on system-average rates associated with COMFIT purchases.

A: The results of my rate-impact analysis, assuming the lowest avoided cost (average system fuel) and the highest system cost (RFP renewables), and using Synapse's proposed COMFIT rates, are summarized in Table 5.[14]

[14] I did not include in Table 5 the results with the export price, which are between the base fuel and RPF renewables cases, are close to the former.

Table 5: First-year COMFIT Rate Effects

	Case Number and Description				
	1 Small Wind	2 Mostly Wind	3 Balanced	4 High Tidal	5 High Penetration
Thousands of Dollars per Year If Avoiding					
Base Fuel	$4,089	$32,465	$49,124	$91,913	$151,058
RFP Renewables	$3,445	$13,755	$24,741	$66,690	$108,803
Rate Increase					
Base Fuel	0.3%	2.6%	3.9%	7.3%	12.0%
RFP Renewables	0.3%	1.1%	2.0%	5.3%	8.7%

These values will vary over the years, depending on the rate at which COMFIT projects are installed and the price of fuel.

In 2012–2014, the COMFIT resources would mostly back down existing resources, so the rate increase would be something like the "base fuel" values in Table 5. Since NSPI currently projects that it is currently short on renewable energy for meeting its 2015 and 2020 renewable obligations, as shown in Exhibit PLC-3, NSPI would be adding more renewables in 2015 and thereafter. Any energy provided by COMFIT projects would reduce the amount of market renewables NSPI purchases or NSPI-owned additions. Hence, the avoided supply from 2015 on would be the cost of non-COMFIT renewables.

The small wind capacity, by itself, has a relatively modest rate effect, which may be tolerable to facilitate the public-policy interest in allowing small public involvement in renewable energy. The larger COMFIT portfolios, especially those with large amount of tidal power, become quite expensive for ratepayers.

Q: Might these rate effects be justified to increase the amount of renewables in the NSPI resource plant?

A: No. NSPI will meet its RES targets, whether through COMFIT, RFPs, or NSPI ownership. Neither NSPI nor the Board has shown any interest in acquiring renewable energy in excess of the RES. If the government, the Board, or NSPI decide that additional renewable energy should be acquired, that energy should be acquired at minimum cost, while meeting any other related goals.

Q: If the Board wanted to increase NSPI's renewable supply, or reduce NSPI's use of coal, would COMFIT projects at Synapse's proposed rates be an efficient mechanism for achieving those goals?

A: No. For any given increase in customer bills (and the accompanying level of stress on consumers and the economy), Synapse's COMFIT rates would result in less renewable energy than alternative procurement approaches, including lower COMFIT rates, RFP procurement, purchases from new hydro facilities in Labrador, and NSPI construction.

The questions before the Board in this proceeding have to do with whether government targets for renewable energy, and reductions in emissions of carbon, mercury, or other pollutants will be achieved in a least-cost manner, or in an unnecessarily expensive manner, paying more for wind, biomass and hydro projects than they would get through an RFP and buying large amounts of tidal resources that cost many times as much as renewable alternatives.

Q: Are there any of the COMFIT technology categories that particularly concern you?

A: Yes. It would be difficult to justify imposing on consumers the exorbitant prices that Synapse proposes for small wind and tidal contracts, or even the reduced prices I summarize in Table 6. As I demonstrated in Section VII, the costs of purchased or NSPI-owned wind energy are a small fraction of the proposed small-wind and tidal COMFIT rates.

Even if the COMFIT projects were displacing the coal combustion, rather other renewables, it would be difficult to justify the proposed small-wind and tidal COMFIT rates compared to the combined financial and environmental costs of coal. In the consultation portion of this proceeding, Sierra Club Canada provided a study of the environmental costs of coal, which also included some information on subsidies.[15] The study's high-end estimate of externality costs is about $290/MWh in 2012 dollars; even adding that estimate to the $46/MWh average cost of fuel would not produce a total cost approaching the $452/MWh for small wind and $652 for tidal proposed by Synapse.

There may be other justifications for some amount of small wind (such as facilitating renewable projects that can be undertaken directly by households and small businesses, or distributing visible renewable-energy projects widely in the province) and tidal (such as attracting the nascent tidal-power to build demonstration projects, research facilities, and even production facilities in Nova Scotia).

Q: Do the Renewable Energy Regulations address the problem of these very expensive resources?

A: Only with respect to small wind projects, whose total COMFIT capacity is limited to 5 MW. I interpret the capacity cap as being intended to limit the potential rate effect of these uneconomic projects, while allowing at least 100 projects to be implemented province-wide, promoting other goals. Unfortunately, the regulations do not impose similar limits on tidal projects.

[15]Epstein, PR, "Full cost accounting for the life cycle of coal," in *Ecological Economics Reviews*, Annals of the New York Academy of Sciences, 1219: 73–98.

IX. Recommended Rates and Tariff Provisions

Q: Please summarize your recommendations regarding the COMFIT rates.

A: The corrections I was able to quantify in Sections III–VI are summarized in Table 6. The "corrected" line is generally greater than the sum of the values above, due to round-off and the interactions of the various adjustments.

Table 6: Summary of Corrections to Synapse's Rate Proposals,
Dollars per MWh

	Small Wind	Large Wind	Biomass	Hydro	Tidal
Synapse Proposed	$452	$139	$156	$140	$652
Adjustments					
Biomass formula			-$7		
Wind CF		−$22			
6% debt, 11% equity	−$52	−$13		−$7	
Development Return					−$254
Land Donation		−$4		−$1	−$2
Reduced Development Cost		−$5			−$28
Property-Tax Relief				−$15	
Total	−$52	−$44	−$7	−$22	−$284
Corrected	$400	$102	$150	$114	$381
Change	−12%	−27%	−4%	−19%	−42%

I was not able to quantify the effects of in-kind donations, although those may be very important for some projects, especially the small wind projects.

Q: Have you estimated that rate effects for the development cases you described in Section VIII?

A: Yes. Table 7 presents the rate impacts in the same form and with the same assumptions as in Table 5.

Table 7: First-Year Bill Effect, Corrected Rates

	Case Number and Description				
	1 Small Wind	2 Mostly Wind	3 Balanced	4 High Tidal	5 High Penetration
Thousands of Dollars per Year If Avoiding					
Base Fuel	$3,565	$24,392	$38,147	$60,755	$98,676
RFP Renewables	$2,921	$2,829	$12,085	$34,693	$54,743
Rate Increase					
Base Fuel	0.3%	1.9%	3.0%	4.8%	7.9%
RFP Renewables	0.2%	0.2%	1.0%	2.8%	4.4%

With the corrected COMFIT rates, the increases in customer bills are much more modest than with Synapse's proposed tariffs.

Q: What tariff language has Synapse proposed?

A: Synapse did not propose tariff language.

Q: When tariff language is developed, what provisions should be included?

A: The tariff should limit eligibility to projects that meet or exceed the following requirements:

- approval from the Energy Minister,
- the requirements of Section 20 of the Renewable Electricity Regulations,
- in the case of small wind, are within the 5 MW statutory limit,
- will not generate more than the minimum load on the substation serving the feeder to which the generator would connect, minus the capacity of generators already connected to the feeder.

While approval from the Minister should cover the second and third bullets, it is generally prudent to include all applicable requirements in the tariff, to reduce confusion and prevent ineligible projects from receiving the tariff rate.

In addition, I recommend that the Board limit the amount of tidal power allowed on the COMFIT rate, to limit the bill effects from tidal to those from small wind. (Regulations already limit he amount of small-wind capacity eligible for COMFIT). With my recommended tariffs, 3.5 MW of tidal generation would increase rates by about the same amount as 5 MW of small wind. With the Synapse tariffs, 2 MW of tidal generation would have the same effect as 5 MW of small wind. A 3.5 MW limit would allow for several demonstration tidal projects. Synapse assumes a 500 kW project size, and tidal turbines are often quite small, as the following examples suggest:

- Verdant's New York turbines are 35 kW, and its proposed turbines for Cornwall, Ontario would be 60–80 kW;
- Oceanflow Energy is currently developing 35-kW and 55-kW machines;
- Ocean Renewable Power Company's TGU turbine is 60 kW;[16]
- New Energy Corporation produces 5 kW to 25 kW Encurrent turbines, and is developing units up to 250 kW;
- Lucid Energy's PowerPipe turbines are currently produced in 5-kW increments;
- Marine Current Turbines has deployed 300-kW and 1.2-MW units;
- the OpenHydro turbine being tested in the Bay of Fundy is 1 MW.

Q: Does this conclude your testimony?

A: Yes.

[16] This appears to be the firm that Synapse refers to as Ocean Power Generation Systems or ORPG.

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.

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

HONORS

Chi Epsilon (Civil Engineering)

Tau Beta Pi (Engineering)

Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

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

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

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

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

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

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

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

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

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

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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; Supplemental, October 2010; Reply, October 2010.

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

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

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

251. **NSUARB** P128.10, Port Hawkesbury Biomass Project; Nova Scotia Consumer Advocate. Direct, June 2010.

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

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

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

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

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

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

Exhibit PLC-2: RFP Prices for Distribution-Connected Wind Projects

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Exhibit PLC-1: NSPI Summary of RES Compliance Status

Nova Scotia Renewable Energy Supply	2011	2013	2015	2020	Source	Energy
NS Electricity Sales Forecast (GWh) (Note 1)	11,603	11,558	11,328	10,635		
RES Requirement (%) (Note 2)	5%	10%	25%	40%		
Renewable Energy Requirement (GWh) (Note 3)	580	1,156	2,832	4,254		
Pre 2001 Renewable Energy (GWh)						
NSPI Hydro			970	970	NSPI	Hydro
IPP Hydro (Morgan Falls, Black River)			4	4	IPP	Hydro
IPP Biomass (Brooklyn Energy, Taylor Lumber)			157	157	IPP	Biomass
Total Pre 2001 Renewable Energy			1,131	1,131		
Post 2001 Renewable Energy - Committed (GWh)						
NSPI Wind (Existing, Nuttby, Digby) (Note 4)		261	261	261	NSPI	Wind
Port Hawkesbury Biomass Project		388	388	388	NSPI	Biomass
FPL Energy Pubnico	88	88	88	88	IPP	Wind
Confederation Power Inc.	55	57	57	57	IPP	Wind
Halifax Renewable Energy Corp.	9	9	9	9	IPP	Biogas
RESL	64	64	64	64	IPP	Wind
Shear Wind	145	169	169	169	IPP	Wind
RMS Energy	165	165	165	165	IPP	Wind
Maryvale	16	16	16	16	IPP	Wind
IPPs Distribution connected (December 19, 2008 RFP)		125	125	125	IPP	Various
Total Post 2001 Renewable Energy - Committed	542	1,342	1,342	1,342		
Total Renewable Energy Supply (GWh)	542	1,342	2,473	2,473		
Surplus / (Shortfall) (GWh) (Note 5)	(38)	186	(359)	(1,781)		
Options for 2015 and beyond Renewable Energy Supply						
Co-generation Large Scale Biomass (GWh)			170	170	IPP	Biomass
IPP and NSPI Large Scale Wind Projects (GWh)			600	600-1,500	IPP/NSPI	Wind
NSPI Co-firing (GWh)			150	150-300	NSPI	Biomass
Import Power - eg. Lower Churchill Muskrat Falls (GWh)				1,000-2,000	Import	Hydro
Community based Feed-in-Tariff (COMFIT) (GWh)			50-300	50-600	COMFIT	Various
New NSPI Small Hydro (GWh)			0-10	0-10	NSPI	Hydro
Bay of Fundy Tidal (GWh)			0-10	0-300	Various	Hydro

Notes:

1) NSPI 2011 Base Cost of Fuel FAM Forecast, August 16, 2010; NSPI 10 Year Energy and Demand Forecast, April 30, 2010.
2) RES for 2011 and 2013 are based on renewable energy sources post 2001; 2020 figure is a target only
3) Renewable energy requirement excludes any planning contingency for margin of safety with resource uncertainties
4) NSPI renewable energy not eligible for 2011 RES
5) In the event of a shortfall in 2011, additional renewable energy will be supplied with RES qualified import power

Prepared February 2011