STATE OF CONNECTICUT

BEFORE THE DEPARTMENT OF PUBLIC UTILITY CONTROL

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Review of Peaking Generation Projects	)	**Docket 08-01-01**
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DIRECT TESTIMONY OF

PAUL CHERNICK AND JONATHAN WALLACH

ON BEHALF OF

THE OFFICE OF CONSUMER COUNSEL

Resource Insight, Inc.

APRIL 8, 2008

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I. Identification & Qualifications

A. Paul Chernick

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

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

Q: Summarize your professional education and experience.

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

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

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

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified approximately two hundred times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in 24 states and two Canadian provinces, and two Federal agencies.

Q: Have you testified previously before the Connecticut Department of Public Utility Control (the Department)?

A: Yes. I testified in

- Docket No. 83-03-01, a United Illuminating (UI) rate case, on behalf of the Office of Consumer Counsel (OCC), on Seabrook costs.
- Docket No. 83-07-15, a Connecticut Light and Power (CL&P) rate case, on behalf of Alloy Foundry, on industrial rate design.
- Docket No. 99-02-05, the CL&P stranded-cost docket.
- Docket No. 99-03-04, the UI stranded-cost docket.
- Docket No. 99-03-35, the UI standard-offer docket.
- Docket No. 99-03-36 (initial phase), the CL&P-standard-offer docket.
- Docket No. 99-08-01, investigation into electric capacity and distribution.
- Docket No. 99-09-12, the nuclear-divestiture plan for CL&P and UI.
- Docket No. 99-09-03, on the performance-based ratemaking proposal of Connecticut Natural Gas.
- Docket No. 99-09-12 RE01, on the Millstone auction.
- Docket No. 99-03-36 RE03, on CL&P's Generation Services Charge.

- Dockets Nos. 99-04-18 Phase 3 and 99-09-03 Phase 2, on the proposed earnings-sharing mechanism of Southern Connecticut Natural Gas and Connecticut Natural Gas.
- Docket No. 03-07-02, on behalf of AARP, on the distribution investment plan and rates for CL&P.
- Docket No. 03-07-01, on behalf of AARP, on the application of the rate cap to CL&P's transitional standard offer.
- Dockets No. 03-07-01RE1 and 03-07-15RE2, on CL&P and UI requests for incentives for mitigating transitional standard offer costs.
- Docket 05-07-18, on whether capacity contracts impose costs on the electric utilities.
- Docket 06-01-08, on multiple rounds of procurement results, on lessons learned from the procurements, and on procurement options.
- Docket 05-07-14PH2, on the cost-effectiveness of capacity contracts proposed under the Energy Independence Act.
- Docket 07-08-24, on the process for the current procurement of peaker capacity.

Except as noted, this testimony was on behalf of the OCC. I also testified on behalf of the OCC in Connecticut Siting Council Docket No. 217, on transmission upgrades to southwestern Connecticut.

B. Jonathan Wallach

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

A: I am Jonathan F. Wallach. I am vice president of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Please summarize your professional education and experience.

A: I have worked as a consultant to the electric-power industry for more than two decades. From 1981 to 1986, I was a research associate at Energy Systems Research Group. In 1987 and 1988, I was an independent consultant. From 1989 to 1990, I was a senior analyst at Komanoff Energy Associates. I have been in my current position at Resource Insight since September of 1990.

Over the last twenty-seven years, I have advised clients on a wide range of economic, planning, and policy issues including: electric-utility restructuring; wholesale-power market design and operations; transmission pricing and policy; market valuation of generating assets and purchase contracts; power-procurement strategies; integrated resource planning; cost allocation and rate design; and energy-efficiency program design and planning.

My professional qualifications are further summarized in Exhibit PC-JW-2.

II. Introduction

Q: On whose behalf are you testifying?

A: Our testimony is sponsored by the Office of Consumer Counsel.

Q: What is the purpose of your direct testimony?

A: The Office of Consumer Counsel has asked us to review the projects proposed in response to the Department's order in Docket No. 07-08-24.

Q: What standards are applicable to this question?

A: Section 50 of Public Act 07-242 (Act) directs the Department to receive, review and approve, approve with modifications, or reject proposals to build peaking units within 120 days of its receipt of complete proposals. The Department is required to approve all proposals unless it demonstrates, based on the principles of General Statutes of Connecticut § 16-19e, that a proposal is not in the interest of ratepayers.

Q: What documents did you review?

A: We reviewed the Department's order in Docket No. 07-08-24, and filings and discovery responses from all seven bidders as follows:

- Bridgeport Energy II (BEII), which offered options 1 and 2, differing in type of turbine.
- Bridgeport Peaking Project (BPP).
- CL&P, which offered projects in Waterbury and Lebanon.
- FirstLight.
- the joint venture of UI and NRG (GenConn), which offered four proposals for up to ten units at the Devon, Middletown, and Montville generating stations.
- Maxim, which filed qualifications for two options but proposed only one.
- PSEG.

III. Summary

Q: Please summarize your recommendations regarding the approval or rejection of proposals.

A: Based on our analysis to this point, we recommend that the Department approve 681 MW of summer capacity comprising Option 4 from GenConn for 188 MW at Devon, the proposal from PSEG for 133 MW at New Haven Harbor, and Option 2 from BEII for 360 MW at in Bridgeport.

The Department should reject all other proposals, including the following

- Bridgeport Energy II, Option 1, which is exclusive of BEII's Option 2;
- Bridgeport Peaking Power Project;

- CL&P's Waterbury and Lebanon projects;
- FirstLight;
- GenConn Options 1–3, which would add generation at Middletown and/or at Montville;[1]
- Maxim.

In light of the problems with BPP's proposal—the lack of a site, an anomalously low estimate of turbine costs, claiming 10-minute reserve capability for a technology that may not provide it, and failure to specify a gas-supply index—we are not sanguine about the prospects for the successful operation of BPP.

The combination of PSEG and GenConn Option 4 is slightly less expensive per kW than the larger GenConn Option 2, and we expect the forward-reserve and uplift benefits to ratepayers to decline as the portfolio grows in size. While we selected PSEG over GenConn's Middletown proposal, the Department might reasonably choose the larger Middletown plant, depending on its assessment of the incremental benefits of additional capacity and hard-to-analyze benefits. Alternatively, adding Middletown to our recommended portfolio would only slightly change our expected net benefits to ratepayers, but would result in a rather large supply commitment in this process and increase the risk of purchasing more capacity than will ultimately be cost-effective.

The remaining proposals are all more expensive than our recommended proposals and GenConn's Middletown proposal, and the benefits to Connecticut consumers decline rapidly for purchases over 700 MW. Consequently the net

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[1] GenConn's Options 1 and 3 consist of units included in proposal 2. Whether the Department needs to formally reject these proposals is a legal point we will not address.

benefits of adding those proposals to the approved portfolio would be strongly negative. In addition to differences in contract prices per kilowatt, our recommendations reflect the disadvantages of GenConn's Montville project (the least expensive of the proposals after those described above) and CL&P's Lebanon project (the next-least expensive). These are oil-only plants, which are not likely to generate any energy margin under normal conditions and would offer less shelter from energy-price spikes that may result from outages of major Connecticut generators (especially Millstone) or transmission lines.

We continue to review and analyze the available data and we may update our recommendations in the course of this hearing.

Q: What are your other recommendations?

A: The Department should retain the right to compel approved projects to engage in specific strategies for participating in ISO-NE wholesale markets, particularly with regard to the choice of bidding into LFRM or participating in the energy market, the choice of bidding into the ten-minute or thirty-minute LFRM if participating in LFRM, and the setting of the bid price for each market. The projects should be required to pursue a prudent strategy of maximizing revenues at reasonable levels of risk, with the understanding that ratepayers will bear the costs and benefits of that strategy.

The Department should also clarify certain contract provisions, as we describe in Section VII. Finally, the Department should clarify that, once contracts are approved, it will not countenance any material amendments to their terms and conditions.

IV. Valuation of Peaking Capacity

Q: What components did you consider in your estimation of the value of peaking capacity?

A: We considered the value of peaking capacity in terms of the following eight factors:

- The effect on the forward capacity market (FCM) price.
- The FCM revenues that would be credited against the project's cost.
- The effect on the Connecticut locational-forward-reserve-market (LFRM) price and potentially on other LFRM prices, and the resulting allocation of LFRM costs to Connecticut ratepayers.
- The LFRM revenues that would be credited against the project's cost.
- The reduction in uplift costs that is likely to result from having more quick-start reserves on the system, so that steam units would less often need to be dispatched out of economic order for reliability.
- The *energy margin* (energy revenues minus fuel costs) that the project would earn, dispatching at the prices allowed for LFRM resources.
- The energy margin that the project could earn, dispatching at its variable costs, if it is not an LFRM resource.
- The effect on market energy price of operation as either LFRM or economically-dispatched resources.

For most of these factors, we modeled the benefits generically, for arbitrary amounts of capacity. The energy effects depend on each project's heat rate, fuel price, location, and variable O&M, so we modeled them individually in terms of energy effects.

A. Forward Capacity Price

Q: What are the prospects for capacity prices in the ISO-NE market?

A: In the first forward-capacity auction, for June 2010 through May 2011, the final price of capacity was $4.50/kW-month, the minimum allowed, compared to the ISO's estimate of $7.50/kW-month for the cost of new peaking capacity. There was about 2,050 MW of excess capacity at the floor price; prorating of the FCM price to this excess cleared capacity will produce an effective price of $4.254/kW-month for 2010–2011. Several proposed generation projects, dozens of demand resources, and imports from Quebec and New Brunswick also did not clear at the floor price, but would have been available at higher prices. In all, about 3,300 MW of excess capacity was offered at or below ISO's estimate of the cost of new peaking capacity.

Some Connecticut projects with incentives or contracts did not bid into the 2010–2011 capacity auction, including the 620-MW Kleen combined-cycle plant, which appears to be scheduled for commercial operation in time for the 2011–2012 auction. Additional resources are likely to be added, including demand reductions from state- and utility-sponsored energy-efficiency programs, renewables driven by high prices for energy and renewable credits, and perhaps some capacity developed by Massachusetts municipal utilities with low-cost tax-exempt financing. All this excess capacity would tend to keep the FCM price depressed for a few more years. Even were 500 MW of existing resources retired or deactivated, the excess capacity from the 2010 FCA would cover two years of the ISO's expected load growth, and the addition of Kleen would cover another year, suggesting that the FCM price is unlikely to rise above $4.50/kW-month until sometime after 2014, or reach the $7.50/kW-month level until after 2016.[2]

For 2011–2012, the FCM floor price will be $3.60/kW-month. In 2012–2013, the FCM floor price would be determined in part by the clearing price in the 2011–2012 auction, but could be as low as $2.95/kW-month.

The low capacity prices may result in retirement of older units and withdrawal of some demand-response offers. In particular, ISO-NE required the 330 MW of capacity at Norwalk Harbor Units 1 and 2 to remain on line for 2010–2011, due to inadequacy in the transmission security margin. These units will apparently be shut down once additional installed capacity is available in Connecticut, from some contribution of transmission upgrades connecting Lake Road to the Connecticut system and additions of Waterbury, the CMEEC peaker, and Kleen. Since NRG bid Norwalk Harbor at $6/kW-month in the FCA, it will probably shut the plant as soon as it is allowed to do so and keep it offline at least until the market capacity price rises above $6/kW-month.

Q: How would these low FCM prices affect the value of the projects proposed in this proceeding?

A: The effect would be indirect. The projects are likely to bid into the LFRM at relatively low prices (although the Department should retain the authority to prescribe the projects' bidding strategies, to maximize total ratepayer benefits). The price actually paid for LFRM resources is the LFRM clearing price (currently at the price cap of $14 in Connecticut), minus the FCM price. Hence, the total revenues for capacity and reserves is essentially independent of the

[2]As we have seen in this proceeding, the cost of new peaking capacity, at least in Connecticut, is well over $7.50/kW-month, even with the lower-cost financing available with a long-term contract.

FCM price. However, the higher the LFRM increment (the LFRM clearing price minus the FCM price) and the lower FCM price, the greater the incentive for eligible resources to ensure that they are selected in the LFRM, potentially resulting in lower total reserve plus capacity prices.

B. Effects on Forward Capacity Prices

Q: What effect would these projects have on FCM prices?

A: This additional capacity may extend the period of time before load growth, exports, deactivations, or retirements erase the current surplus and increase FCM prices to levels approaching the ISO's estimate of the cost of new capacity. In the 2010–2011 FCA, about 1,300 MW of resources withdrew between prices of $8 and $4.50/kW-month. Assuming this average supply-curve slope of 0.23¢/kW-month for each MW of low-price resource in the FCA, and about 8,000 MW of market-based capacity purchases in Connecticut, a rough estimate is that every additional MW of FCM resource added through this process would reduce Connecticut's FCM bill by about $220,000 annually.[3] However, this estimate is subject to considerable uncertainty, since the slope of the supply curve in the first FCA varied by orders of magnitude from one round of the auction to the next, with no obvious pattern, and so the price effects of the projects would be very sensitive to the exact mix of bids in any one auction.

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[3]Connecticut's peak load is about 26.7% of New England's peak. About 34,000 MW cleared in the 2010–2011 FCA, so Connecticut's capacity obligation is a bit over 9,000 MW. About 1,000 MW of this obligation is met with (or hedged by) existing or planned long-term purchases (Kleen, Waterbury, Waterside, Bridgeport RESCo) and CMEEC entitlements. The remaining 8,000 MW is purchased in shorter-term purchases, as part of Standard Service, Supplier of Last Resort and direct purchases by retail customers.

Q: Would that benefit continue throughout the life of the projects?

A: No. This effect would exist only as long as all of the following are true

- The projects, or the resulting price reductions, do not cause the retirement, deactivation or export of equivalent existing resources.
- The FCM price clears above the administrative floor; the FCM price cleared at the floor in the auction for 2010–2011 and is likely to do so again in the auction for 2011–2012.
- The FCM price remains below the cost of generic new peaking capacity. Above that cost the operation of the FCA would simply result in the projects avoiding or delaying equivalent new resources, rather than reducing prices.

Realistically, the projects may only depress FCM prices for perhaps three to seven years, from the time the FCM clearing price rises above the ISO's floor price to the time prices reach the cost of generic new peaking capacity. The start and duration of this period will depend on load growth, the rate of development of other resources (e.g., energy efficiency, demand response, renewables, municipal generation, Canadian export projects), and capacity prices in New York, PJM, and Ontario, which will determine whether New England is a net importer or exporter of capacity.

Q: How much might this price effect be worth to Connecticut consumers?

A: If the Department selects a 500 MW portfolio in this proceeding, the annual FCM-price benefit to Connecticut consumers could be on the order $1/kW-month, or $100 million annually for so long as the price is below the cost of generic new peaking capacity. As we noted above, the actual benefit in any year could be much greater or smaller.

C. *Locational Forward Reserve Market Effects*

Q: How would addition of various projects proposed in this proceeding affect the cost of LFRM to Connecticut consumers?

A: These complex effects are as follows:

- As long as the forward reserve capacity in Connecticut is less than the ISO's requirement (currently 1,155 MW in the four-month summer, 1,370 MW in the winter), additional LFRM capacity will be purchased at the cap price (currently $14/kW-month, minus the FCM price).
- Once the Connecticut LFRM bids exceed the requirement, the Connecticut price for LFRM supply will be set by selecting the lowest-cost combination of bids that satisfy the location and regional requirements.
- In addition to LFRM requirements in Connecticut, Northeast Massachusetts (NEMA), and the rest of the system (ROS), the ISO requires that certain amounts of LFRM (currently 800 MW in the summer and 850 MW in the winter) be capable of coming on line within ten minutes, rather than the thirty minutes required for other LFRM capacity. This ten-minute non-spinning reserve (TMNSR) can have a higher price than thirty-minute operating reserve (TMOR). A single resource can contribute to meeting both its local LFRM requirement and the system-wide TMNSR requirement. The vast majority of TMNSR supply has come from ROS resources.[4]
- The TMNSR costs and TMOR costs incurred by ISO-NE are allocated separately to load in the various zones (ROS, NEMA, Connecticut) with a

[4]Small amounts of NEMA (60 MW) and Connecticut (90 MW) TMNSR have been offered in various auctions, but as long as the LFRM price is $14/kW-month, there is no reason for resources to take on the additional costs and risks of guaranteeing 10-minute response.

complicated formula. The costs for each type of LFRM are spread over the on-peak hours of the season, and the costs for each hour are allocated in proportion to the product of the zone's hourly load and the seasonal price of that type of LFRM in that zone.[5] When no TMNSR is offered in Connecticut, the ISO allocation formula imputes a price of $14/kW-month. When no TMOR cleared in ROS, the ISO set the ROS TMOR price to zero and allocated no TMOR costs to ROS load.

- For any projects approved in this proceeding, and for certain resources under construction (Waterside and the CMEEC peaker), the LFRM revenues will flow to Connecticut ratepayers. While all of the LFRM revenues from the first couple hundred MW of such resources will benefit Connecticut ratepayers, only a fraction of those LFRM costs will be allocated to Connecticut.

Q: Have other parties modeled the benefit of adding LFRM resources in Connecticut?

A: Yes. The Department used one such model in the order in Docket No. 07-08-24. In a study filed by GenConn, Olaf Karstens of Thorndike Crossing, Inc., provided another analysis.

Q: How did the Department model LFRM prices?

A: The Department assumed the following market-clearing prices for LFRM, as a function of capacity acquired through this proceeding (Docket No. 07-08-24, Table 3):

[5] Connecticut has actually been split into two zones—SWCT and the rest of state—for this allocation, potentially complicating the computation. The Connecticut zones may be merged, once the 345 kV upgrades are complete.

MW added	Clearing Price ($/MW-mo.)
0	$14,000
280	$14,000
380	$13,000
480	$12,000
600	$10,800
800	$8,800

The Department assumed that 37.86% of the Connecticut LFRM costs are borne by Connecticut load (Docket No. 07-08-24, Attachment 1). The Department did not account for the LFRM revenues to ratepayers from Waterside and the CMEEC peaker; did not distinguish between TMOR and TMNSR markets and prices; and did not distinguish between summer and winter prices.

Q: What does the Department's LFRM price curve suggest for the incremental benefits to Connecticut ratepayers?

A: The following table summarizes our assessment of the net LFRM benefit, using the Department's assumptions. For simplicity, we have not removed the FCM offset from any of our LFRM analyses, so the revenues and benefits include FCM values.

	Project LFRM Revenue		Conn LFRM Costs	Connecticut Share of Cost		Net Incremental Benefit	
MW	Total	Incremental		Total	Incremental	Total	$/kW-month
0			$168 M	$64 M			
280	$47 M	$47 M	$215 M	$82 M	$18 M	$29 M	$8.70
380	$59 M	$12 M	$216 M	$82 M	$0 M	$12 M	$10.13
480	$69 M	$10 M	$213 M	$81 M	($1)M	$11 M	$8.89
600	$78 M	$9 M	$208 M	$79 M	($2)M	$11 M	$7.52
800	$84 M	$7 M	$190 M	$72 M	($7)M	$13 M	$5.53

Q: How did Thorndike model LFRM prices?

A: Thorndike appears to have assumed that the summer and winter LFRM bid curves in Connecticut would be the same as the bid curve for Winter 2007-2008, with the addition of Waterbury, Cos Cob, and any incremental capacity acquired in this proceeding.[6]

Q: What would the Thorndike's LFRM price curve suggest for the incremental benefits to Connecticut ratepayers?

A: As we understand it, the incremental benefits of LRFM capacity addition would rise and fall erratically, following the winter curve. We believe that the bid curve would reduce the incremental benefits of the first 300 megawatts of LFRM added beyond the Connecticut requirement, but increase the incremental benefits of LFRM added beyond that point.

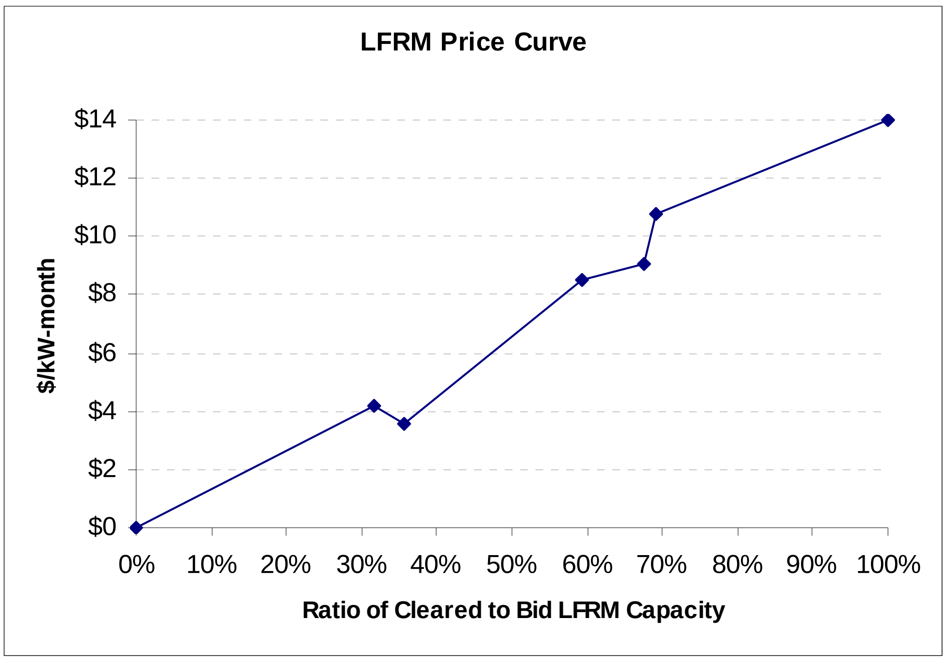
Q: How did you model LFRM prices?

A: We assumed that the LFRM price in any of the twelve markets—two products (TMNSR and TMOR) for three regions for two seasons—would vary with the ratio of cleared to offered capacity in the market. Of the 36 LFRM prices determined to date in the first auctions, only seven have been below the $14/kW-month cap: six for ROS and the most recent winter TMOR price for NEMA. In the first winter auction, the ROS TMNSR price equaled the TMOR price, since the marginal resource selected was a TMNSR resource; we treated those results as a single observation. The prices and the corresponding ratio of cleared to bid capacity in the markets were as follows:

[6]It is not clear how Thorndike constructed this curve, since the data do not appear to have been released, except as separate graphs for SWCT and the rest of state. ("A Report on Operation of the New England Reserve Markets," ISO-NE Market Monitoring, October 1, 2007.)

Auction	Ratio of cleared to bid capacity	LFRM Price ($/kW-month)
ROS TMOR W 07-08	0%	$0.00
ROS TMOR W 06-07[7]	32%	$4.20
ROS TMOR S 07[8]	36%	$3.55
NEMA TMOR W 07-08	59%	$8.50
ROS TMNSR W 07-08	68%	$9.05
ROS TMNSR S 07	69%	$10.80
All others	100%	$14.00

The graph below shows the relationship between LFRM price and the ratio of cleared to offered capacity.



Based on this pattern, we modeled the LFRM price in each market as:

LFRM price = Cap Price–16.2 × (1–Cleared-to-Offered Ratio)

[7]Since the total ROS requirement constraint was binding, this could also be thought of as representing a 47% ratio for the combined market.

[8]Since the total ROS requirement constraint was binding, this could also be thought of as representing a 61% ratio for the combined market.

Since the LFRM was reduced by $3.05/kW-month of transitional ICAP throughout this period, we reduced the $14 cap price to $10.95, resulting in an LFRM premium of:

$$\text{LFRM premium} = \$10.95 – \$16.20 \times (1 – \text{Cleared-to-Offered Ratio})$$

with a minimum LFRM premium of $1.50/kW-month, to cover the costs and risks of participation in the LFRM.

Q: What does your model of the LFRM price curve suggest for the incremental benefits to Connecticut ratepayers of peaking projects?

A: The following table presents our results for LFRM effects to ratepayers for additions in 100-MW increments of TMOR capacity (both summer and winter) under contract to the Connecticut utilities.

Added MW	Cost Allocated to Conn.	Net of Contract & CMEEC Revenues	Incremental Net Cost	$/kW-month from Base	Incremental $/kW-month
Base	$128 M	$109			
100	$137 M	$105 M	($4)M	-3.1	-3.1
200	$147 M	$102 M	($7)M	-3.1	-3.1
300	$156 M	$98 M	($11)M	-3.1	-3.1
400	$142 M	$77 M	($32)M	-6.6	-17.2
500	$127 M	$59 M	($50)M	-8.4	-15.4
600	$115 M	$44 M	($65)M	-9.1	-12.6
700	$104 M	$31 M	($78)M	-9.3	-10.4

Q: How do these results change if some of the added capacity is TMNSR, rather than TMOR?

A: The benefits to Connecticut customers increase, for the following three reasons:

- When Connecticut TMNSR is selkected instead of ROS TMNSR, the TMNSR price and/or the total cost of meeting the ROS requirement falls, reducing costs to all New England consumers.

- Connecticut pays a higher share of TMOR costs than of TMNSR costs, so shifting costs to TMNSR reduces Connecticut's total LFRM cost allocation.
- Once the ROS requirement is no longer met entirely by TMNSR, some TMOR will be taken in ROS, resulting in allocation of a share of system-wide TMOR costs to ROS. In contrast, no ROS TMOR was taken in Winter 2007–2008, and ROS apparently paid none of the TMOR costs.
- Once the Connecticut TMOR price has fallen below the ROS TMNSR price, Connecticut peakers may be able to earn higher revenues for TMNSR, reducing net costs to Connecticut customers.

D. Effect on Uplift

Q: How did the Department model the effect of peaker capacity on uplift?

A: The Department assumed that Connecticut second-contingency uplift cost will decline linearly from $36.06 M annually with no additional peakers to $5.3 M with 290 MW, based on the belief that "Uplift will be largely but not completely eliminated when the LFRR is fully met by the quick start resources" (Docket No. 07-08-24 at 15).

The Department did not include any value from the contribution of Connecticut peaking capacity to relieving pool-wide first-contingency uplift costs.

Q: How did you model the effect of peaker capacity on uplift?

A: In the absence of any specific data on the origins of the uplift costs, or any indication of how those costs would respond to the addition of LFRM capability, we looked to the experience of other zones with excess LFRM capability. Both the southeastern Massachusetts zone and the west-and-central Massachusetts zone have routinely had uplift costs, and even Maine has occasionally had some uplift costs, even though there is no shortage of LFRM capacity outside Connecticut and NEMA. We therefore assumed that eliminating uplift would require more capacity than meeting the LFRM requirement.

Based on data similar to that used by the Department, we assumed that about $30 million in annual uplift costs would be avoidable through addition of peakers. Uplift charges may increase in June 2010, when 2,330 MW of RMR contracts with Connecticut generators expire (Bridgeport Harbor 2; Middletown 2, 3, 4 and 10; Milford 1 and 2, and Montville 5, 6, 10 and 11; and New Haven Harbor).[9] Under the RMR contracts, these units are dispatched at cost both in the energy market and as required for uplift. After the expiration of those contracts, the generators will be allowed to select their bid prices to maximize their owners' total expected revenues. Those bid prices may well be higher than the costs charged under the RMR contracts.

Based on experience in other regions, we assumed that the reduction in uplift cost would equal the square root of the added peaker capacity. That benefit would be $17 million for the first 300 MW (to which the Department's model assigns all the uplift benefits), $22 million at 500 MW, and $28 million at 800 MW.

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[9]As noted above, Norwalk Harbor will remain under RMR for at least until May 2011, but will probably be deactivated sometime shortly thereafter.

V. Energy Margin

Q: How did the Department model energy margin for generic peaking capacity?

A: The Department assumed that the peakers would operate at a 3% capacity factor with an average $50/MWh margin, producing a profit of $13/kW-year for the first 290 MW and nothing above that level.

Q: How did you estimate net energy margin?

A: For each of the proposals, we estimated the hourly dispatch and energy profit for a period of 23 months (April 2006 through February 2008). For each hour, we compared the hourly day-ahead price at a pricing node representative of the project to the minimum of daily oil or gas cost for the project at a 14,300 heat rate, which we assumed would be the threshold price imposed by ISO-NE.[10]

For each hour in which the plant would dispatch, we computed its energy margin, assuming the plant ramped instantly to full capacity. The energy margin was the hourly nodal price, minus the sum of

- the plant's fuel price for that day, times its full-load summer heat rate,[11]
- variable O&M in dollars per MWh, plus variable O&M in dollars per hour divided by summer capacity.

For proposals with variable O&M per start, we checked each start to ensure that the margin during the unit run could have covered the start-up costs.

[10]For oil-only projects, we used only oil prices; conseuently the projects never dispatched.

[11]The use of summer heat rate reduces the margin since winter heat rate tends to be lower, but the use of full-load heat rate increases the margin.

If not, we eliminated the margin. For starts that were economic, we reduced the margin by the proposal's cost per start.

Since not all proposals were complete with respect to estimates of gas delivery costs, we used estimates from other projects. In particular, we used Maxim's estimate of gas delivery costs for BPP.

Q: What were your results?

A: The oil-only plants (GenConn's Montville and CL&P's Lebanon) have no energy margin in this analysis. The other plants have energy margins that range from $0.39/kW-month to $1.08/kW-month. See Exhibit PC-JW-3.

Q: Do you believe that these energy margins are representative of future margins?

A: While we believe that this range of values is reasonable, energy margins will be very sensitive to the relationship between peak energy prices and gas prices. Energy prices may rise as the RMR contracts in Connecticut and other parts of New England expire and the owners are allowed to set energy prices or to shut units down. On the other hand, the addition of new capacity may reduce market energy prices.

We do not believe that the uncertainties in these values are critical in any of the decisions facing the Department.

VI. Ranking and Selection of Peaking Proposals

A. Overview

Q: Please describe the peaking projects proposed in response to the Department's Request for Proposals.

A: Seven suppliers responded to the Department's RFP with detailed proposals for a variety of peaking projects. The projects proposed by each of these suppliers are as follows:

1. **Bridgeport Energy II.** Bridgeport Energy II, a joint venture of LS Power Associates and Dynegy, Inc., proposes construction of a two-unit gas-fired combustion-turbine facility at the site of the Bridgeport Energy plant. BEII offers the option of installing either two General Electric 7FA or two Siemens SGT6-5000F turbines. The former option ("Option 1") would provide 314MW of summer capacity; the latter option ("Option 2") has a proposed summer rating of 360MW.

2. **Bridgeport Peaking Power.** A joint venture of NED Peaking Power, LLC and Central Hudson Enterprises Corporation, Bridgeport Peaking Power proposed a single STG6-PAC5000F gas turbine with a summer-rated capacity of 180 MW. Subsequent to submittal of its detailed proposal, BPP revealed that it did not have control of the site for its proposed facility. According to a March 27, 2008 letter to the Department, BPP is currently in discussions with a landowner for an alternative site.

3. **Connecticut Light and Power.** CL&P proposed two peaking projects. One project, to be located in at an existing substation in Lebanon, would comprise four General Electric LM6000 combustion turbines burning

ultra-low-sulfur diesel, with a summer rating of 156 MW for the four-unit facility. The second project would be located in Waterbury and would comprise two GE LM2500+ gas-fired turbines with a summer rating of 56 MW.

4. **FirstLight Power Enterprises.** FirstLight proposes to site a single 94-MW gas-fired GE LMS-100 combustion turbine at the Shepaug Hydro Station.

5. **GenConn Energy.** A joint venture of United Illuminating Company and NRG Energy, Inc., GenConn proposed four project options consisting of varying numbers of GE LM6000 combustion turbines to be located at the Devon, Middletown, and Montville generating stations. The largest of the four options ("Option 1") consists of four gas-fired turbines each at Devon and Middletown and two diesel-fired turbines at Montville, with a proposed rating of 469 MW.[12] The smallest option ("Option 4") consists of four gas-fired turbines at the Devon station, for a total capacity of 188 MW.

6. **Maxim Power.** Maxim Power proposes to install two gas-fired GE LM6000 combustion turbines at a site in Bridgeport. The proposed facility would have a summer capacity of 93 MW.

7. **PSEG Power.** PSEG Power proposes to site three GE LM6000 combustion turbines at its New Haven Harbor generating station. These turbines will burn natural gas as their primary fuel and have a summer rating of 133 MW.

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[12] This package of ten turbines has a combined summer rating of 481 MW when burning their primary fuels. However, GenConn proposes to set the contract capacity for the eight gas-fired turbines at the summer-rated capacity when burning ultra-low-sulfur distillate oil. (See GenConn's detailed proposal at 12.)

Exhibit PC-JW-4 summarizes the major cost and performance characteristics for each of the proposed projects.

Q: Which of these projects do you recommend for Department approval?

A: Based on the information available to us at this time, we recommend approval of the BEII Option 2, PSEG Power, and GenConn Energy Option 4 projects, with a combined capacity of 681 MW.

Q: Please explain the basis for this selection.

A: We evaluated the project proposals in a multi-step process. First, we ranked projects on the basis of the bidders' forecasts of Annual Fixed Revenue Requirements ("AFRR"). Specifically, we calculated the *levelized* AFRR for each project, and then ranked projects on the basis of their levelized AFRR per unit of capacity.[13] We then tested this ranking against a number of sensitivities. Next, we identified the top-tier projects and determined the LFRM and other economic benefits associated with different portfolio combinations of these projects. Finally, we identified the preferred portfolio based on economic performance and a number of qualitative factors.

B. Initial Ranking

Q: Please describe the ranking of project proposals by levelized AFRR.

A: Exhibit PC-JW-4 provides our estimate of the levelized AFRR per kW-month for each project proposal.[14] As shown, levelized AFRRs range from a low of

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[13]Standard accounting treatment produces a stream of AFRRs that has its highest value at the start of the recovery period and then declines gradually over time. The levelized AFRR is that constant value for AFRR that yields the same discounted value over the recovery period as the actual declining stream of AFRRs.

[14]Exhibit PC-JW-4 also provides the levelized AFRR per kW-month for the CL&P projects without A&G costs, since CL&P claims that there will be no incremental A&G associated with

$12.42/kW-month for the BPP project to a high of $19.99/kW-month for CL&P's Waterbury proposal.

Exhibit PC-JW-5 provides two rankings of project proposals in order of increasing cost. One ranking includes the levelized AFRR for the cheapest GenConn option, Option 2, which entails 376 MW of LM6000 turbines at the Devon and Middletown stations. This ranking also includes the *incremental* levelized AFRR of adding 93 MW of LM6000 capacity at the Montville Station to the Option 2 package to create Option 1 (the second cheapest of the four options.)[15] The other ranking substitutes GenConn Option 4, consisting of 188 MW of capacity at the Devon station, for GenConn Option 2 and the Montville addition to Option 2.[16] Both rankings show the levelized AFRR only for the cheaper of the two BEII options (the 360 MW Siemens turbine.)

The project proposals fall into two tiers when ranked on the basis of levelized AFRR. With GenConn Option 2 and the Montville Addition, the levelized AFRRs for the five top-tier projects—BEII Option 2, BPP, PSEG, GenConn Option 2, and the Montville addition to Option 2—range from $12.37/kW-month to $13.09/kW-month. With GenConn Option 4, the levelized AFRRs for the four top-tier projects—BEII Option 2, BPP, PSEG, and GenConn Option 4—all fall below $13/kW-month. In contrast, the levelized AFRRs for the four projects in the bottom tier of either ranking exceed $14/kW-month. The

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these facilities. As discussed below, regardless of the merits of this claim, the CL&P projects are not competitive even when assuming no incremental A&G.

[15]The Montville increment is only applicable to Option 2.

[16]Neither ranking includes GenConn Option 3, since incremental cost of moving from Option 4 to Option 3 is not competitive with other projects' costs. Moreover, there is a negative incremental cost of moving from Option 3 to Option 2.

average cost of the bottom-tier projects exceeds that of the top-tier projects by about 40%.

C. Sensitivity Analyses

Q: How did you test the sensitivity of this rank ordering?

A: We tested the sensitivity of our results to the following factors:

- Connecticut Light & Power's claims regarding incremental A&G costs,
- netting of energy margins against levelized AFRRs,
- bidders' estimates of capital cost and forecasts of O&M cost escalation,
- project sponsors' assumptions regarding interest rates for project debt.

Q: What is CL&P's position regarding the treatment of incremental A&G costs?

A: Connecticut Light & Power asserts that its proposed projects do not incur A&G costs in addition to those already recovered through distribution rates.[17] CL&P therefore provides two AFRR forecasts, one with the embedded A&G fully allocated to the proposed projects and one without any allocated A&G.

As indicated in Exhibit PC-JW-4, eliminating allocated A&G reduces levelized AFRR by about $1.5/kW-month for the Lebanon project and about $1.8/kW-month for the Waterbury project.

Q: What is the impact on project ranking if you assume no allocation of A&G costs to the CL&P projects?

A: There is no change in the ranking of either the Lebanon or the Waterbury project.

[17] See page 9 of CL&P's detailed proposal.

Q: What is the impact on project ranking when energy margins are netted from levelized AFRR?

A: Reducing each project's levelized AFRR by our estimate of net energy margin changes the relative ranking among the top-tier projects, but does not alter the ranking of any other projects.[18] As shown in Exhibit PC-JW-6, netting of energy margins moves GenConn Option 2 from fourth place to a first-place tie with BEII Option 2 and moves PSEG above BPP in the ranking. All other projects retain their places in the rank order under this sensitivity.

The effect is similar in the ranking with GenConn Option 4. In this case, netting of energy margins moves GenConn Option 4 simply swaps positions in the rank order with BPP.

Q: Please describe your sensitivity analysis of project fixed costs.

A: In its December 14 2007 Decision in Docket No. 07-08-24, the Department made two rulings with regard to the recovery of fixed-cost expenditures. First, the Department (at 28) deemed prudent actual capital expenditures up to 5% in excess of the capital cost estimate in the project proposal. Second, the Department (at 30) stated that it would allow recovery of prudently-incurred annual increases in fixed O&M and A&G costs of up to 2% over the general rate of inflation.

We therefore tested the sensitivity of project ranking to increases in fixed costs to the upper end of the Department's zone of reasonableness. Specifically, we increased bidders' estimates of project capital cost by 5% in their forecasts of AFRRs. In addition, we increased assumed fixed O&M and A&G annual

[18] The derivation of energy margins is described above Section V.

escalation rates to 4.5%.[19] We limited this sensitivity analysis to the five projects in the first and second tiers, since there is an average cost differential of 40% between this group and the remaining four projects. In other words, this sensitivity is unlikely to change the rank of the four bottom-tier projects relative to the top five projects.

Q: How does this fixed-cost sensitivity affect levelized AFRRs?

A: This sensitivity increases levelized AFRRs for the top five projects by 6%–10%. As indicated in Exhibit PC-JW-7, the only impact on project ranking is that BPP and PSEG swap places in the rank order.

Q: Why did you test the sensitivity of the project ranking to debt interest rates?

A: The interest rates assumed in AFRR forecasts for the top five projects ranged from 6.5% (PSEG) to 8% (BPP). The variation in assumed interest rates across forecasts might reasonably be explained by differences in project leverage, bidder's credit quality, or other project-specific factors. However, these variations may simply be due to differences in bidders' assumptions regarding general economic conditions, such as the risk-free rate of interest over the next thirty years.

In order to ensure that the relative ranking of the top five projects was insensitive to variations in assumptions regarding market-wide factors, we re-calculated AFRRs by equalizing interest rates across these five projects. In other words, we assumed that the variation in bidders' interest rates was due solely to differences in assumptions regarding non-project factors.

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[19]All project sponsors other than CL&P assumed annual escalation for fixed O&M costs and A&G at the 2.5% value deemed by the Department to be the general rate of inflation We have not compared CL&P's more complex escalation assumptions to the Department projection.

Q: How does the project ranking change when interest rates are equalized across the five lowest-cost projects?

A: Project ranking is fairly stable under equalization of interest rates. As shown in Exhibit PC-JW-8, the only effect is that PSEG and GenConn Option 2 swap positions in the rank order.

D. Valuation of Top-Tier Projects

Q: How did you analyze various portfolios of proposals?

A: We started by computing the capacity value of various portfolios of the top-tier projects, using the Resource Insight valuation model described in Section IV. Rather than adding generic units with 100 MW of LFRM capacity both winter and summer, we added specific combinations of proposed projects, with the winter and summer capacity claimed by the proponents. We also added back the FCM revenues of $3.05/kW-month that we deleted from the LFRM pricing analysis.

The combinations we considered are shown in Exhibit PC-JW-9. We did not evaluate any portfolio of less than 300 MW, since that would not be enough capacity to unpin the LFRM price from the ceiling price. The table provides our estimates of each portfolio's LFRM, uplift and FCM value to Connecticut ratepayers. The exhibit also shows for each portfolio the total value net of the portfolio's AFRR.

E. Preferred Portfolio

Q: How did you narrow down this group of portfolios?

A: The estimates of portfolio net value (Exhibit PC-JW-9) do not include the value of ten-minute non-spinning reserve, energy margin, effects on energy or FCM market prices, or value of the energy-market hedge. To account for these benefits, we increased the net value of each portfolio by $1/kW-month.

We then narrowed our assessment to those portfolios with the highest net value, including the $1 adder for other benefits. In order to assess the trade-offs between BPP value and risks, we ranked and evaluated the highest-value portfolios without BPP separately from those with BPP.

The highest-value portfolios without BPP are as follows:

Portfolio		**S MW**	**Total Quantified Benefit** ($M)	**AFRR** ($M)	**Net Cost** ($M)	**With $1/kW-Mo. Other Benefit**
7	PSEG+GC2+BEII	869	($157)	$131	($26.1)	($36.5)
10	BEII+GC2	736	($138)	$111	($27.3)	($36.1)
12	BEII+PSEG+GC4	681	($130)	$102	($27.3)	($35.4)

The highest-value portfolios with BPP are as follows:

Portfolio			**S MW**	**Total Quantified Benefit** ($M)	**AFRR** ($M)	**Net Cost** ($M)	**With $1/kW-Mo. Other Benefit**
BPP+		BEII+					
12	16	PSEG+GC4+BPP	861	($156)	$129	($26.9)	($37.2)
	13	GC4+BPP	728	($137)	$109	($28.3)	($37.0)
11	14	PSEG+BPP	673	($129)	$100	($28.8)	($36.9)
10	15	GC2+BPP	916	($163)	$137	($25.1)	($36.1)

Q: How did you reach your recommendation?

A: We considered the tradeoffs among net costs, the size of the commitment, and risks of BPP. We are reluctant to recommend in a single procurement the commitment to more than 800 MW, or about 10% of Connecticut's capacity obligation not yet under long-term contract. As the amount taken in this procurement rises, the certainty of marginal uplift benefits declines. Given those concerns, we rejected portfolio 7, which beats portfolios 10 and 12 only if other benefits materialize.

In our view, the risks of BPP outweigh the benefits of its lower proposed cost. In addition, since BEII offers no TMNSR, and BPP offers only half its capacity as TMNSR, we believe that the Department should acquire at least 300 MW of TMNSR capacity before considering BPP.

Q: What is your recommendation?

A: Our basic recommendation at this time is that the Department approve BEII Option 2, GenConn Option 4, and PSEG. (Portfolio 12), to minimize exposure to excessive purchases and to diversify the providers of capacity.

If the Department wants to acquire slightly more capacity, it could instead approve just BEII Option 2 and GenConn Option 2 (Portfolio 10).

If the Department is willing to acquire more capacity than we have recommended, taking the risks of declining value and the lack of diversification in acquisition timing, it could take the BPP proposal in addition to either Portfolio 12 (producing Portfolio 16) or Portfolio 10 (producing Portfolio 15).

Q: Do you have any concerns or qualifications regarding this recommendation?

A: Yes. There are many uncertainties in our analysis, including

- the ratemaking rules the Department will apply,
- the detailed meaning of some proposal components,
- the relative risk of increases in costs from each proposal to operation,
- the future requirements for Connecticut LFRM as additional transmission is developed,
- the operation of the LFRM cost-allocation process over time,
- the evolution of market supply curves for regional TMNSR and Connecticut LFRM over time,

- whether demand resources will be able to participate in the LFRM market and if so, how much forward-reserve demand resource capacity will be developed in Connecticut,
- retirement of older capacity in Connecticut,
- the extent to which adding LFRM in Connecticut will reduce Connecticut uplift,
- future energy and capacity prices, and
- the rate at which the markets respond to the addition of the projects built as a result of this proceeding.

There are also project-specific valuation uncertainties. For example, Bridgeport Energy II and BPP proposed larger units (180 MW) than the LM6000 units (smaller than 50 MW each) of GenConn and PSEG. The large units ramp to full output more slowly, and would not be fully eligible for ten-minute non-spinning reserve. Outage of a single BEII or BPP unit would have a greater adverse effect on market energy prices and on LFRM performance penalties than would an outage of any of the GenConn and PSEG units. We have not been able to quantify this effect.

Q: How does your recommendation incorporate these uncertainties?

A: We selected more capacity than the minimum that would reduce LFRM prices from the price cap, but less than could be justified by more aggressive assumptions. In addition, our analysis continues. We will review the analysis by the Prosecutorial consultants and any issues raised in discovery, and we may revise our recommendations in the course of this proceeding.

VII. Revisions to the Standard Contract

Q: Is the current version of the Standard Contract in need of modification?

A: Yes. There are a number of terms and provisions of the current version of the Standard Contract that are either

- inconsistent with the Department's rulings in the December 14, 2007 Decision in Docket No. 07-08-24;
- inconsistent with other terms and provisions of the Standard Contract;
- undefined, ill-defined, or ambiguous.

These problematic contract elements should be corrected to ensure that ratepayers receive the full benefits of the selected peaking projects.

Q: How is the Standard Contract inconsistent with the Decision?

A: The Decision (at 30) establishes a guarantee that the recoverable amount of fuel costs will be determined based on the heat rate specified in the project proposal. This is not properly reflected in the provisions of the Standard Contract.

Exhibit E of the Standard Contract defines the heat rate used to determine fuel costs not as the heat rate set forth in the project proposal, but as the heat rate "established at the time the contract is executed or at Commercial Operation."[20] Ratepayers are at risk of recovering a lower margin on energy sales than expected from the project proposal, if the contract heat rate established pursuant to Exhibit E is higher than originally proposed.

[20]The definition in Exhibit E is also inconsistent with the definition contained in the General Definitions of the Standard Contract. This latter definition defines the contract heat rate as the value specified in the project proposal, consistent with the Decision.

There is also a potential inconsistency between the Decision and the Standard Contract (as well as within the Standard Contract) with respect to the treatment of capacity and heat-rate degradation over time. The Decision (at 32, emphasis in original) is explicit in its allocation of degradation risk to the seller:

> The proposed payment mechanism in Section 6.1 of the Standard Contract stipulates that the EDC's payments to the Supplier are equal to the monthly revenue requirement less the market value of the products based on the *contract* quantities and performance specifications. The Supplier retains the *actual* market revenues, therefore the Supplier will be rewarded or penalized for over- or under-performance.

Nonetheless, Attachment 4 to the Decision, which sets forth the operating data to be submitted in project proposals, requests bidders to "define [a] proposed mechanism to account for performance (capacity and heat rate) degradation." This introduces ambiguity by allowing for the possibility that the Standard Contract will incorporate adjustments for degradation in the contract quantities for capacity and heat rate, and thus shift degradation risk to ratepayers, contrary to the intent of the Decision.

Q: Are there other cost-recovery provisions of the Decision that are inadequately reflected in the Standard Contract?

A: Yes. The Decision caps the amount of recoverable fuel costs by capping the heat-rate value used in the calculation of fuel costs at 105% of the value specified in the project proposal. The Standard Contract lacks an explicit provision establishing this cap. Instead, its Exhibit E contains a cursory and imprecise description of the cap mechanism.

Q: Which provisions of the Standard Contract are ambiguous?

A: There are two ambiguous provisions. First, Exhibit E specifies that LFRM revenue will be calculated based on the "LFRM Clearing Price." However, this calculation does not specify whether the term "LFRM Clearing Price" refers to the clearing price for ROS or for the Connecticut zone (to the extent that there is price separation), or whether the term refers to the clearing price for the TMNSR or TMOR markets. This provision should be clarified to ensure that the calculation relies on the clearing price for the reserve market that suppliers bid into, as directed by the Department.

Second, Sections 6.1(d)(i) and 6.1(d)(ii) create ambiguity by referring to the undefined terms "ISO Market Revenues," "ISO NE Market Revenues," and "ISO Market Prices." This ambiguity can be eliminated by replacing all such references with the term "Contract Monthly Market Revenue," which is defined in Exhibit E.

Q: Which terms are undefined in the Standard Contract?

A: The following undefined terms are referenced in the Standard Contract:

Term	Reference
Confirmed FCM Contract Quantity	Section 3.3(e)
ISO Market Revenues	Section 6.1(d)(i)
ISO NE Market Revenues	Sections 6.1(d)(i), 6.1(d)(ii)
ISO Market Prices	Section 6.1(d)(ii)
Contract Summer Availability	Exhibit E
Contract Winter Availability	Exhibit E
Contract Forced Outage Rate	Exhibit E
Contract Unit Start Fuel	Exhibit E

These terms should either be defined or, where appropriate, replaced with already-defined terms.

Q: Does this conclude your testimony?

A: Yes.

Exhibit PC-JW-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)

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Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

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

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"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.

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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 of 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.

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, Consolidate 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, Consolidate Edison Electric Rate Case; 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.

Exhibit PC-JW-2

Qualifications of

JONATHAN F. WALLACH

Resource Insight, Inc.
5 Water Street
Arlington, Massachusetts 02476

SUMMARY OF PROFESSIONAL EXPERIENCE

1990–Present **Vice President, Resource Insight, Inc.** Provides research, technical assistance, and expert testimony on electric- and gas-utility planning, economics, regulation, and restructuring. Designs and assesses resource-planning strategies for regulated and competitive markets, including estimation of market prices and utility-plant stranded investment; negotiates restructuring strategies and implementation plans; assists in procurement of retail power supply.

1989–90 **Senior Analyst, Komanoff Energy Associates.** Conducted comprehensive cost-benefit assessments of electric-utility power-supply and demand-side conservation resources, economic and financial analyses of independent power facilities, and analyses of utility-system excess capacity and reliability. Provided expert testimony on statistical analysis of U.S. nuclear plant operating costs and performance. Co-wrote *The Power Analyst*, software developed under contract to the New York Energy Research and Development Authority for screening the economic and financial performance of non-utility power projects.

1987–88 **Independent Consultant.** Provided consulting services for Komanoff Energy Associates (New York, New York), Schlissel Engineering Associates (Belmont, Massachusetts), and Energy Systems Research Group (Boston, Massachusetts).

1981–86 **Research Associate, Energy Systems Research Group.** Performed analyses of electric utility power supply planning scenarios. Involved in analysis and design of electric and water utility conservation programs. Developed statistical analysis of U.S. nuclear plant operating costs and performance.

EDUCATION

BA, Political Science with honors and Phi Beta Kappa, University of California, Berkeley, 1980.

Massachusetts Institute of Technology, Cambridge, Massachusetts. Physics and Political Science, 1976–1979.

PUBLICATIONS

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

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

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

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

"Benefit-Cost Ratios Ignore Interclass Equity" (with Paul Chernick et al.), *DSM Quarterly*, Spring 1992.

"Consider Plant Heat Rate Fluctuations," *Independent Energy*, July/August 1991.

"Demand-Side Bidding: A Viable Least-Cost Resource Strategy" (with Paul Chernick and John Plunkett), *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

"New Tools on the Block: Evaluating Non-Utility Supply Opportunities With *The Power Analyst*, (with John Plunkett), *Proceedings of the Fourth National Conference on Microcomputer Applications in Energy*, April 1990.

REPORTS

"Integrated Portfolio Management in a Restructured Supply Market" (with Paul Chernick, William Steinhurst, Tim Woolf, Anna Sommers, and Kenji Takahashi). 2006. Columbus, Ohio: Office of the Ohio Consumers' Counsel.

"First Year of SOS Procurement." 2004. Prepared for the Maryland Office of People's Counsel.

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

"Peak-Shaving–Demand-Response Analysis: Load Shifting by Residential Customers" (with Brian Tracey). 2003. Barnstable, Mass.: Cape Light Compact.

"Electricity Market Design: Incentives for Efficient Bidding; Opportunities for Gaming." 2002. Silver Spring, Maryland: National Association of State Consumer Advocates.

"Best Practices in Market Monitoring: A Survey of Current ISO Activities and Recommendations for Effective Market Monitoring and Mitigation in Wholesale Electricity Markets" (with Paul Peterson, Bruce Biewald, Lucy Johnston, and Etienne Gonin). 2001. Prepared for the Maryland Office of People's Counsel, Pennsylvania Office of Consumer Advocate, Delaware Division of the Public Advocate, New Jersey Division of the Ratepayer Advocate, Office of the People's Counsel of the District of Columbia.

"Comments Regarding Retail Electricity Competition." 2001. Filed by the Maryland Office of People's Counsel in U.S. FTC Docket No. V010003.

"Final Comments of the City of New York on Con Edison's Generation Divestiture Plans and Petition." 1998. Filed by the City of New York in PSC Case No. 96-E-0897.

"Response Comments of the City of New York on Vertical Market Power." 1998. Filed by the City of New York in PSC Case Nos. 96-E-0900, 96-E-0098, 96-E-0099, 96-E-0891, 96-E-0897, 96-E-0909, and 96-E-0898.

"Preliminary Comments of the City of New York on Con Edison's Generation Divestiture Plan and Petition." 1998. Filed by the City of New York in PSC Case No. 96-E-0897.

"Maryland Office of People's Counsel's Comments in Response to the Applicants' June 5, 1998 Letter." 1998. Filed by the Maryland Office of People's Counsel in PSC Docket No. EC97-46-000.

"Economic Feasibility Analysis and Preliminary Business Plan for a Pennsylvania Consumer's Energy Cooperative" (with John Plunkett et al.). 1997. 3 vols. Philadelphia, Penn.: Energy Coordinating Agency of Philadelphia.

"Good Money After Bad" (with Charles Komanoff and Rachel Brailove). 1997. White Plains, N.Y.: Pace University School of Law Center for Environmental Studies.

"Maryland Office of People's Counsel's Comments on Staff Restructuring Report: Case No. 8738." 1997. Filed by the Maryland Office of People's Counsel in PSC Case No. 8738.

"Protest and Request for Hearing of Maryland Office of People's Counsel." 1997. Filed by the Maryland Office of People's Counsel in PSC Docket Nos. EC97-46-000, ER97-4050-000, and ER97-4051-000.

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

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

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

"Report on Entergy's 1995 Integrated Resource Plan." 1996. On behalf of the Alliance for Affordable Energy (New Orleans).

"Preliminary Review of Entergy's 1995 Integrated Resource Plan." 1995. On behalf of the Alliance for Affordable Energy (New Orleans).

“Comments on NOPSI and LP&L’s Motion to Modify Certain DSM Programs.” 1995. On behalf of the Alliance for Affordable Energy (New Orleans).

“Demand-Side Management Technical Market Potential Progress Report.” 1993. On behalf of the Legal Environmental Assistance Foundation (Tallahassee)

“Technical Information.” 1993. Appendix to “Energy Efficiency Down to Details: A Response to the Director General of Electricity Supply’s Request for Comments on Energy Efficiency Performance Standards” (UK). On behalf of the Foundation for International Environmental Law and Development and the Conservation Law Foundation (Boston).

“Integrating Demand Management into Utility Resource Planning: An Overview.” 1993. Vol. 1 of “From Here to Efficiency: Securing Demand-Management Resources” (with Paul Chernick and John Plunkett). Harrisburg, Pa.:Pennsylvania Energy Office

“Making Efficient Markets.” 1993. Vol. 2 of “From Here to Efficiency: Securing Demand-Management Resources” (with Paul Chernick and John Plunkett). Harrisburg, Pa.: Pennsylvania Energy Office.

“Analysis Findings, Conclusions, and Recommendations.” 1992. Vol. 1 of “Correcting the Imbalance of Power: Report on Integrated Resource Planning for Ontario Hydro” (with Paul Chernick and John Plunkett).

“Demand-Management Programs: Targets and Strategies.” 1992. Vol. 1 of “Building Ontario Hydro’s Conservation Power Plant” (with John Plunkett, James Peters, and Blair Hamilton).

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

“Comments of Public Interest Intervenors on the 1993–1994 Annual and Long-Range Demand-Side Management and Integrated Resource Plans of New York Electric Utilities” (with Ken Keating et al.) 1992.

“Review of Jersey Central Power & Light’s 1992 DSM Plan and the Demand-Side Management Rules” (with Paul Chernick et al.). 1992. Report to the New Jersey Department of Public Advocate.

“Review of Rockland Electric Company’s 1992 DSM Plan and the Demand-Side Management Rules” (with Paul Chernick et al.). 1992.

“Initial Review of Ontario Hydro’s Demand-Supply Plan Update” (with David Argue et al.). 1992.

“Comments on the Utility Responses to Commission’s November 27, 1990 Order and Proposed Revisions to the 1991–1992 Annual and Long Range Demand Side Management Plans” (with John Plunkett et al.). 1991.

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

"Profitability Assessment of Packaged Cogeneration Systems in the New York City Area." 1989. Principal investigator.

"Statistical Analysis of U.S. Nuclear Plant Capacity Factors, Operation and Maintenance Costs, and Capital Additions." 1989.

"The Economics of Completing and Operating the Vogtle Generating Facility." 1985. ESRG Study No. 85-51A.

"Generating Plant Operating Performance Standards Report No. 2: Review of Nuclear Plant Capacity Factor Performance and Projections for the Palo Verde Nuclear Generating Facility." 1985. ESRG Study No. 85-22/2.

"Cost-Benefit Analysis of the Cancellation of Commonwealth Edison Company's Braidwood Nuclear Generating Station." 1984. ESRG Study No. 83-87.

"The Economics of Seabrook 1 from the Perspective of the Three Maine Co-owners." 1984. ESRG Study No. 84-38.

"An Evaluation of the Testimony and Exhibit (RCB-2) of Dr. Robert C. Bushnell Concerning the Capital Cost of Fermi 2." 1984. ESRG Study No. 84-30.

"Electric Rate Consequences of Cancellation of the Midland Nuclear Power Plant." 1984. ESRG Study No. 83-81.

"Power Planning in Kentucky: Assessing Issues and Choices—Project Summary Report to the Public Service Commission." 1984. ESRG Study No. 83-51.

"Electric Rate Consequences of Retiring the Robinson 2 Nuclear Plant." 1984. ESRG Study No. 83-10.

"Power Planning in Kentucky: Assessing Issues and Choices—Conservation as a Planning Option." 1983. ESRG Study No. 83-51/TR III.

"Electricity and Gas Savings from Expanded Public Service Electric and Gas Company Conservation Programs." 1983. ESRG Study No. 82-43/2.

"Long Island Without the Shoreham Power Plant: Electricity Cost and System Planning Consequences; Summary of Findings." 1983. ESRG Study No. 83-14S.

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"Customer Programs to Moderate Demand Growth on the Arizona Public Service Company System: Identifying Additional Cost-Effective Program Options." 1982. ESRG Study No. 82-14C.

"The Economics of Alternative Space and Water Heating Systems in New Construction in the Jersey Central Power and Light Service Area, A Report to the Public Advocate." 1982. ESRG Study No. 82-31.

"Review of the Kentucky-American Water Company Capacity Expansion Program, A Report to the Kentucky Public Service Commission." 1982. ESRG Study No. 82-45.

"Long Range Forecast of Sierra Pacific Power Company Electric Energy Requirements and Peak Demands, A Report to the Public Service Commission of Nevada." 1982. ESRG Study No. 81-42B.

"Utility Promotion of Residential Customer Conservation, A Report to Massachusetts Public Interest Research Group." 1981. ESRG Study No. 81-47

PRESENTATIONS

"Electricity Market Design: Incentives for Efficient Bidding, Opportunities for Gaming." NASUCA Northeast Market Seminar, Albany, N.Y., February 2001.

"Direct Access Implementation: The California Experience." Presentation to the Maryland Restructuring Technical Implementation Group on behalf of the Maryland Office of People's Counsel. June 1998.

"Reflecting Market Expectations in Estimates of Stranded Costs," speaker, and workshop moderator of "Effectively Valuing Assets and Calculating Stranded Costs." Conference sponsored by International Business Communications, Washington, D.C., June 1997.

EXPERT TESTIMONY

1989 **Mass. DPU** on behalf of the Massachusetts Executive Office of Energy Resources. Docket No. 89-100. Joint testimony with Paul Chernick relating to statistical analysis of U.S. nuclear-plant capacity factors, operation and maintenance costs, and capital additions; and to projections of capacity factor, O&M, and capital additions for the Pilgrim nuclear plant.

1994 **NY PSC** on behalf of the Pace Energy Project, Natural Resources Defense Council, and Citizen's Advisory Panel. Case No. 93-E-1123. Joint testimony with John Plunkett critiques proposed modifications to Long Island Lighting Company's DSM programs from the perspective of least-cost-planning principles.

1994 **Vt. PSB** on behalf of the Vermont Department of Public Service. Docket No. 5270-CV-1 and 5270-CV-3. Testimony and rebuttal testimony discusses rate and bill effects from DSM spending and sponsors load shapes for measure- and program-screening analyses.

1996 **New Orleans City Council** on behalf of the Alliance for Affordable Energy. Docket Nos. UD-92-2A, UD-92-2B, and UD-95-1. Rates, charges, and integrated resource planning for Louisiana Power & Lights and New Orleans Public Service, Inc.

1996 **New Orleans City Council** Docket Nos. UD-92-2A, UD-92-2B, and UD-95-1. Rates, charges, and integrated resource planning for Louisiana Power & Lights and New Orleans Public Service, Inc.; Alliance for Affordable Energy. April, 1996.

Prudence of utilities' IRP decisions; costs of utilities' failure to follow City Council directives; possible cost disallowances and penalties; survey of penalties for similar failures in other jurisdictions.

1998 **Massachusetts Department of Telecommunications and Energy** Docket No. 97-111, Commonwealth Energy proposed restructuring; Cape Cod Light Compact. Joint testimony with Paul Chernick, 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.

Massachusetts Department of Telecommunications and Energy Docket No. 97-120, Western Massachusetts Electric Company proposed restructuring; Massachusetts Attorney General. Joint testimony with Paul Chernick, October, 1998. Joint surrebuttal with Paul Chernick, 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.

1999 **Maryland PSC** Case No. 8795, Delmarva Power & Light comprehensive restructuring agreement, Maryland Office of People's Counsel. July 1999.

Support of proposed comprehensive restructuring settlement agreement

Maryland PSC Case Nos. 8794 and 8808, Baltimore Gas & Electric Company comprehensive restructuring agreement, Maryland Office of People's Counsel. Initial Testimony July 1999; Reply Testimony August 1999; Surrebuttal Testimony August 1999.

Support of proposed comprehensive restructuring settlement agreement

Maryland PSC Case No. 8797, comprehensive restructuring agreement for Potomac Edison Company, Maryland Office of People's Counsel. October 1999.

Support of proposed comprehensive restructuring settlement agreement

Connecticut DPUC Docket No. 99-03-35, United Illuminating standard offer, Connecticut Office of Consumer Counsel. November 1999.

Reasonableness of proposed revisions to standard-offer-supply energy costs. Implications of revisions for other elements of proposed settlement.

2000 **U.S. FERC** Docket No. RT01-02-000, Order No. 2000 compliance filing, Joint Consumer Advocates intervenors. Affidavit, November 2000.

Evaluation of innovative rate proposal by PJM transmission owners.

2001 **Maryland PSC** Case No. 8852, Charges for electricity-supplier services for Potomac Electric Power Company, Maryland Office of People's Counsel. March 2001.

Reasonableness of proposed fees for electricity-supplier services.

Maryland PSC Case No. 8890, Merger of Potomac Electric Power Company and Delmarva Power and Light Company, Maryland Office of People's Counsel. September 2001; surrebuttal, October 2001. In support of settlement: Supplemental, December 2001; rejoinder, January 2002.

Costs and benefits to ratepayers. Assessment of public interest.

Maryland PSC Case No. 8796, Potomac Electric Power Company stranded costs and rates, Maryland Office of People's Counsel. December 2001; surrebuttal, February 2002.

Allocation of benefits from sale of generation assets and power-purchase contracts.

2002 **Maryland PSC** Case No. 8908, Maryland electric utilities' standard offer and supply procurement, Maryland Office of People's Counsel. Direct, November 2002; Rebuttal December 2002.

Benefits of proposed settlement to ratepayers. Standard-offer service. Procurement of supply.

2003 **Maryland PSC** Case No. 8980, adequacy of capacity in restructured electricity markets; Maryland Office of People's Counsel. Direct, December 2003; Reply December 2003.

Purpose of capacity-adequacy requirements. PJM capacity rules and practices. Implications of various restructuring proposals for system reliability.

2004 **Maryland PSC** Case No. 8995, Potomac Electric Power Company recovery of generation-related uncollectibles; Maryland Office of People's Counsel. Direct, March 2004; Supplemental March 2004, Surrebuttal April 2004.

Calculation and allocation of costs. Effect on administrative charge pursuant to settlement.

Maryland PSC Case No. 8994, Delmarva Power & Light recovery of generation-related uncollectibles; Maryland Office of People's Counsel. Direct, March 2004; Supplemental April 2004.

Calculation and allocation of costs. Effect on administrative charge pursuant to settlement.

Maryland PSC Case No. 8985, Southern Maryland Electric Coop standard-offer service; Maryland Office of People's Counsel. Direct, July 2004.

Reasonableness and risks of resource-procurement plan.

2005 **FERC** Docket No. ER05-428-000, revisions to ICAP demand curves; City of New York. Statement, March 2005.

Net-revenue offset to cost of new capacity. Winter-summer adjustment factor. Market power and in-City ICAP price trends.

FERC Docket No. PL05-7-000, capacity markets in PJM; Maryland Office of People's Counsel. Statement, June 2005.

Inefficiencies and risks associated with use of administratively determined demand curve. Incompatibility of four-year procurement plan with Maryland standard-offer service.

FERC Dockets Nos. ER05-1410-000 & EL05-148-000, proposed market-clearing mechanism for capacity markets in PJM; Coalition of Consumers for Reliability, Affidavit October 2005, Supplemental Affidavit October 2006.

Inefficiencies and risks associated with use of administratively determined demand curve. Effect of proposed reliability-pricing model on capacity costs.

2006 **Maryland PSC** Case No. 9052, Baltimore Gas & Electric rates and market-transition plan; Maryland Office of People's Counsel, February 2006.

Transition to market-based residential rates. Price volatility, bill complexity, and cost-deferral mechanisms.

Maryland PSC Case No. 9056, default service for commercial and industrial customers; Maryland Office of People's Counsel, April 2006.

Assessment of proposals to modify default service for commercial and industrial customers.

Maryland PSC Case No. 9054, merger of Constellation Energy Group and FPL Group; Maryland Office of People's Counsel, June 2006.

Assessment of effects and risks of proposed merger on ratepayers.

Illinois Commerce Commission Docket No. 06-0411, Commonwealth Edison Company residential rate plan; Citizens Utility Board, Cook County State's Attorney's Office, and City of Chicago, Direct July 2006, Reply August 2006.

Transition to market-based rates. Securitization of power costs. Rate of return on deferred assets.

Maryland PSC Case No. 9064, default service for residential and small commercial customers ; Maryland Office of People's Counsel, Rebuttal Testimony, September 2006.

Procurement of standard-offer power. Structure and format of bidding. Risk and cost recovery.

FERC Dockets Nos. ER05-1410-000 & EL05-148-000, proposed market-clearing mechanism for capacity markets in PJM; Maryland Office of the People's Counsel, Supplemental Affidavit October 2006.

Distorting effects of proposed reliability-pricing model on clearing prices. Economically efficient alternative treatment.

Maryland PSC Case No. 9063, optimal structure of electric industry; Maryland Office of People's Counsel, Direct Testimony, October 2006; Rebuttal November 2006; surrebuttal November 2006.

Procurement of standard-offer power. Risk and gas-price volatility, and their effect on prices and market performance. Alternative procurement strategies.

Maryland PSC Case No. 9073, stranded costs from electric-industry restructuring; Maryland Office of People's Counsel, Direct Testimony, December 2006.

Review of estimates of stranded costs for Baltimore Gas & Electric.

2007 **Maryland PSC** Case No. 9091, rates and rate mechanisms for the Potomac Edison Company; Maryland Office of People's Counsel, Direct Testimony, March 2007.

Cost allocation and rate design. Revenue decoupling mechanism.

Maryland PSC Case No. 9092, rates and rate mechanisms for the Potomac Electric Power Company; Maryland Office of People's Counsel, Direct Testimony, March 2007.

Cost allocation and rate design. Revenue decoupling mechanism.

Maryland PSC Case No. 9093, rates and rate mechanisms for Delmarva Power & Light; Maryland Office of People's Counsel, Direct Testimony, March 2007.

Cost allocation and rate design. Revenue decoupling mechanism.

Maryland PSC Case No. 9099, rates and rate mechanisms for Baltimore Gas & Electric; Maryland Office of People's Counsel, Direct, March 2007; Surrebuttal April 2007.

Cost allocation and rate design. Revenue decoupling mechanism.

Connecticut DPUC Docket No. 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.

Estimation of Energy Margins

			CL&P			**GenConn**				
	BEII	**BPP**	*Lebanon*	*Waterbury*	**FirstLight**	*Devon*	*Middlet'n*	*Montville*	**Maxim**	**PSEG**
Pipeline	Iroquois	TGP-Z6[a]	Oil Only	Algonquin	Algonquin	Iroquois	Algonquin	Oil Only	TGP-Z6	Algonquin
Average $/MMBtu	$8.00	$7.82		$7.96	$7.96	$8.00	$7.96		$7.82	$7.96
LDC		SCG				Yankee	Yankee		SCG	SCG
Gas Delivery $/MMBtu	$0.25	$1.30							$1.30[b]	$0.20[c]
Pricing node	1032	4443	4492	4809	566	397	482	493	341	513
Average LMP	$67.93	$68.64	$66.12	$69.89	$69.85	$67.75	$68.20	$66.21	$67.93	$68.59
Hours Over $100/MWh	1,340	1,435	1,079	1,631	1,576	1,304	1,341	1,072	1,340	1,377
VOM ($/MWh & $/hr ÷ MW)	-	$7.54		$1.53	$11.34	$2.60	$2.60	$2.70	$5.02	-
$/MW/start	$51			$37	$5	$6	$6	$6		$93
Summer Full-Load Heat Rate	10,918	9,411		11,127	9,197	10,088	10,088	9,972	10,330	9,458
Dollars per kW over 23 Months										
Net Rev ($/MW)	$18.3	$10.9		$24.0	$25.5	$22.0	$21.2		$9.0	$21.6
Start Cost ($/MW)	$5.1			$5.2	$0.8	$0.7	$0.8			$10.0
Adjusted for Unecon Starts	$13.7	$10.9		$19.3	$24.8	$21.4	$20.4		$9.0	$13.3
Per kW-Mo.	$0.60	$0.47		$0.84	$1.08	$0.93	$0.89		$0.39	$0.58

NOTES

[a]BPP did not provide an hourly price index. We used Maxim's assumptions.

[b]Maxim's maximum estimate.

[c]PSEG's minimum estimate.

Peaking Project Costs and Characteristics

	Bridgeport Energy II			**CL&P**			**GenConn**					
	Option 1	Option 2	**BPP**	Lebanon	Waterbury	**FirstLight**	Option 1	Option 2	Option 3	Option 4	**Maxim**	**PSEG**
COD	11/30/2010	11/30/2010	5/31/2010	5/31/2010	1/31/2010	4/1/2011	6/1/2010	6/1/2010	6/1/2010	6/1/2010	6/1/2012	6/1/2011
Summer MW	314	360	180	156	56	94	469	376	281	188	93	133
Units	2	2	1	4	2	2	10	8	6	4	2	3
Primary Fuel	NG	NG	NG	Diesel	NG	NG	NG [1]	NG	NG	NG	NG	NG
TMNSR	No	No	No	Yes	Yes	Yes	No [2]	No [2]	No [2]	No [2]	Yes	Yes
FCA Eligibility	2011	2011	2011	2011	2011	2011	2011	2011	2011	2011	2012	2011
Black Start Capability	No	No	Add $500k	Add $500k	Add $500k	Yes	Add $1.5M	Add $1M	Add $1M	Add $500k	Add $1.5M	Yes
Capital Cost (mixed $/summer kW) [3]	1,204	1,101	824	1,157	1,390	1,449	1,087	1,066	1,107	1,046	1,292	1,064
Fixed O&M (2008$/summer kW-yr) [4]	8.74	7.62	35.52	24.84	39.13	18.15	18.96	19.57	20.35	21.53	23.65	14.10
Assumed Expense Escalation	2.50%	2.50%	2.50%	Various escalators	Various escalators	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
ROE	10.25%	10.25%	10.75%	10.50%	10.50%	10.40%	10.25%	10.25%	10.25%	10.25%	9.75%	10.75%
Equity %	50.00%	50.00%	40.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	40.00%	40.00%
Assumed Debt Rate	6.95%	6.95%	8.00%	6.19%	6.19%	7.26%	6.65%	6.65%	6.65%	6.65%	6.50%	6.50%
Debt %	50.00%	50.00%	60.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	60.00%	60.00%
Wtd Cost of Capital	8.60%	8.60%	9.10%	8.35%	8.35%	8.83%	8.45%	8.45%	8.45%	8.45%	7.80%	8.20%
Levelized AFRR ($/summer kW-month)	**$13.65**	**$12.37**	**$12.42**	**$14.78**	**$19.88**	**$17.87**	**$12.76**	**$12.68**	**$13.17**	**$12.79**	**$17.95**	**$12.49**
CL&P Levelized AFRR w/o A&G				$13.29	$18.13							
Incremental Levelized AFRR for Monville Addition							$13.09					

[1] Ultra-low-sulfur distillate for Montville units.
[2] GenConn units capable of providing TMNSR, at DPUC direction. (Response to PRO-113)
[3] Capital cost includes AFUDC.
[4] Fixed O&M includes insurance, excludes taxes.

Project Ranking by Levelized Fixed Revenue Requirement

	Summer Capacity (MW)	Cumulative Capacity (MW)	Levelized AFRR ($/kW-month)	Rank Order	Tier	Tier Average Levelized AFRR	Difference from Tier 1
BEII Option 2	360	360	12.37	1	1		
BPP	180	540	12.42	2	1		
PSEG	133	673	12.49	3	1		
GenConn Option 2	376	1049	12.68	4	1		
GenConn Montville Addition	93	1142	13.09	5	1	12.61	
CL&P Lebanon	156	1298	14.78	6	2		
FIrstLight	94	1392	17.87	7	2		
Maxim	93	1485	17.95	8	2		
CL&P Waterbury	56	1541	19.88	9	2	17.62	39.7%

Substituting GenConn Option 4

	Summer Capacity (MW)	Cumulative Capacity (MW)	Levelized AFRR ($/kW-month)	Rank Order	Tier	Tier Average Levelized AFRR	Difference from Tier 1
BEII Option 2	360	360	12.37	1	1		
BPP	180	540	12.42	2	1		
PSEG	133	673	12.49	3	1		
GenConn Option 4	188	861	12.79	4	1	12.52	
CL&P Lebanon	156	1017	14.78	5	2		
FIrstLight	94	1111	17.87	6	2		
Maxim	93	1204	17.95	7	2		
CL&P Waterbury	56	1260	19.88	8	2	17.62	40.8%

Project Ranking: Energy Margin Sensitivity

	Summer Capacity (MW)	Levelized AFRR ($/kW-month)	Energy Margin ($/kW-month)	Net Cost ($/kW-month)	Rank Order
BEII Option 2	360	12.37	0.60	11.77	1
BPP	180	12.42	0.47	11.95	4
PSEG	133	12.49	0.58	11.92	3
GenConn Option 2	376	12.68	0.91	11.77	1
GenConn Montville Addition	93	13.09	-	13.09	5
CL&P Lebanon	156	14.78	-	14.78	6
FIrstLight	94	17.87	1.08	16.79	7
Maxim	93	17.95	0.39	17.56	8
CL&P Waterbury	56	19.88	0.84	19.05	9

Substituting GenConn Option 4

	Summer Capacity (MW)	Levelized AFRR ($/kW-month)	Energy Margin ($/kW-month)	Net Cost ($/kW-month)	Rank Order
BEII Option 2	360	12.37	0.60	11.77	1
BPP	180	12.42	0.47	11.95	4
PSEG	133	12.49	0.58	11.92	3
GenConn Option 4	188	12.79	0.93	11.87	2
CL&P Lebanon	156	14.78	-	14.78	5
FIrstLight	94	17.87	1.08	16.79	6
Maxim	93	17.95	0.39	17.56	7
CL&P Waterbury	56	19.88	0.84	19.05	8

Project Ranking: Fixed Cost Sensitivity

	Summer Capacity (MW)	Levelized AFRR ($/kW-month)	Rank Order
BEII Option 2	360	13.10	1
BPP	180	13.63	3
PSEG	133	13.44	2
GenConn Option 2	376	13.73	4
GenConn Montville Addition	93	14.08	5

Substituting GenConn Option 4

	Summer Capacity (MW)	Levelized AFRR ($/kW-month)	Rank Order
BEII Option 2	360	13.10	1
BPP	180	13.63	3
PSEG	133	13.44	2
GenConn Option 4	188	13.97	4

Project Ranking: Debt Rate Sensitivity

	Summer Capacity (MW)	Levelized AFRR ($/kW-month)	Rank Order
BEII Option 2	360	12.23	2
BPP	180	12.07	1
PSEG	133	12.55	3
GenConn Option 2	376	12.68	4
GenConn Montville Addition	93	13.09	5

Substituting GenConn Option 4

	Summer Capacity (MW)	Levelized AFRR ($/kW-month)	Rank Order
BEII Option 2	360	12.23	2
BPP	180	12.07	1
PSEG	133	12.55	3
GenConn Option 4	188	12.79	4

Valuation of Peaker Portfolios (Millions of Dollars)

	Portfolio	Summer MW	Net LFRM costs	LFRM Saving to Conn.	Uplift Reduction	FCM revenue @ $3.05/ kW-yr	Total Quantified Benefit	AFRR	Net Cost
	Base		$109						
1	GC2	376	$80	($29)	($19)	($14)	($62)	$57	($4.5)
2	GC2+BPP	556	$47	($62)	($24)	($20)	($106)	$84	($21.6)
3	GC2+PSEG	509	$55	($54)	($23)	($19)	($95)	$77	($17.7)
4	GC2+PSEG+BPP	689	$30	($79)	($26)	($25)	($130)	$104	($26.2)
5	PSEG+GC2+BPP+BEII	1049	$3	($106)	($32)	($38)	($177)	$157	($19.6)
6	PSEG+GC2+BPP+Montville	783	$21	($88)	($28)	($29)	($145)	$119	($26.0)
7	PSEG+GC2+BEII	869	$14	($95)	($29)	($32)	($157)	$131	($26.1)
8	PSEG+GC2+MV	602	$42	($67)	($25)	($22)	($114)	$92	($22.2)
9	BEII	360	$80	($29)	($19)	($13)	($62)	$53	($8.1)
10	BEII+GC2	736	$25	($84)	($27)	($27)	($138)	$111	($27.3)
11	BEII+PSEG	493	$55	($54)	($22)	($18)	($94)	$73	($20.8)
12	BEII+PSEG+GC4	681	$31	($78)	($26)	($25)	($130)	$102	($27.3)
13	BEII+GC4+BPP	728	$25	($84)	($27)	($27)	($137)	$109	($28.3)
14	BEII+PSEG+BPP	673	$31	($78)	($26)	($25)	($129)	$100	($28.8)
15	BEII+GC2+BPP	916	$10	($99)	($30)	($34)	($163)	$137	($25.1)
16	BEII+PSEG+GC4+BPP	861	$14	($95)	($29)	($32)	($156)	$129	($26.9)