STATE OF CONNECTICUT

BEFORE THE DEPARTMENT OF PUBLIC UTILITY CONTROL

Application of the	)	
Connecticut Light and Power Company	)	**Docket No. 03-07-02**
To Amend Its Rate Schedules	)	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

AARP

Resource Insight, Inc.

OCTOBER 1, 2003

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I. Identification and Qualifications

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

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 347 Broadway, Cambridge, 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____PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified approximately one hundred and ninety times on utility issues before various regulatory, legislative, and judicial bodies, including the Arizona Commerce Commission, Connecticut Department of Public Utility Control, District of Columbia Public Service Commission, Florida Public Service Commission, Maryland Public Service Commission, Massachusetts Department of Public Utilities, Massachusetts Energy Facilities Siting Council, Michigan Public Service Commission, Minnesota Public Utilities Commission, Mississippi Public Service Commission, New Mexico Public Service Commission, New Orleans City Council, New York Public Service Commission, North Carolina Utilities Commission, Public Utilities Commission of Ohio, Pennsylvania Public Utilities Commission, Rhode Island Public Utilities Commission, South Carolina Public Service Commission, Texas Public Utilities Commission, Utah Public Service Commission, Vermont Public Service Board, Washington Utilities and Transportation Commission, West Virginia Public Service Commission, Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission.

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, 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.

I also testified on behalf of the Office of Consumer Counsel (OCC) in Connecticut Siting Council Docket No. 217, on the proposed transmission upgrades to southwestern Connecticut.

Q: Are you the author of any publications on utility planning and rate-making issues?

A: Yes. I am the author of publications on rate design, cost allocation, cost recovery, cost-benefit analysis, and other ratemaking issues. Several of my recent papers and report deal with issues in electric and gas industry restructuring, including integrated resource planning and performance-based rate-making. These are listed in my resume.

II. Introduction and Summary

Q: On whose behalf are you testifying?

A: My testimony is sponsored by AARP.

Q: What is the purpose of your direct testimony?

A: I raise two concerns regarding CL&P's filing in this proceeding:

- Whether all of CL&P's current and projected distribution expenditures should be included in rates.
- Whether CL&P should be allowed to treat all power-supply costs as Federally Mandated Costs as defined by Connecticut Public Act 03-221, thereby evading the rate cap imposed by Connecticut Public Act 03-135.

Q: What are your conclusions and recommendations?

A: I have two groups of conclusions and recommendations.

First, some of CL&P's projected distribution expenditures result from the Company's past failure to make sufficient expenditures for distribution maintenance, investment, and staffing.

To the extent that current and future expenditures simply equal the costs of deferred activities, those costs may be properly recoverable from ratepayers. However, if the costs of deferred investments were previously included in rates, CL&P should not charge ratepayers again for those costs.

In addition, if the deferral resulted in damage to equipment, through overloads or mechanical wear, the Company should not recover from ratepayers incremental costs of any of CL&P's deferral decisions that were imprudent. The same is true for the costs of rebuilding a work force previously reduced to improve the Company's earnings.

To avoid passing on to ratepayers costs for which they have already paid, or the costs of CL&P's imprudence, the Department should specify that any distribution rates set in this proceeding are subject to adjustment following an audit and investigation of the extent to which the Company's deferrals increased the total cost of the distribution system, or denied ratepayers the benefits of costs they were charged. At any rate, since the Company is requesting rate recovery for substantial increase in expenditures, ratepayers should get some assurance that they will benefit from these expenditures.

In addition, the Department should add performance standards to the Company's proposed rate plan. The Company has, in the past, failed to make expenditures required for high reliability in favor of increasing return to shareholders. A rate plan with significant penalties for improving performance measures would discourage CL&P from repeating that behavior, and compensate ratepayers to some extent if CL&P does succumb.

Second, the Department should clarify that the distribution rates to be set in this proceeding are maximum rates that will be reduced as necessary over time to fit under the legislative rate cap (along with all other required rate components other than specific federally mandated congestion costs). While the detailed rules for determining the congestion costs will be developed in another docket (apparently Docket No. 03-07-10), it is never too early to clarify important aspects of the evolving regulatory framework. That clarification is particularly important in situations such as the current one, in which the Company seems confused about the manner in which the distribution and generation cost components should be developed.

III. Distribution Expenditures

Q: Please describe the Company's proposed distribution expenditure plan.

A: The Company requests a significant increase in its distribution expenditures for two initiatives described in Company Witness Dana Louth's testimony: first, a major effort to refurbish and replace aging and obsolete distribution equipment, and second, an attrition hiring plan to replace an aging workforce.

Q: How has CL&P quantified the reliability of its distribution system in the documents in this proceeding?

A: The Company uses the following two important standard measures:

- The SAIDI (System Average Interruption Duration Index), which is the number of minutes of outage experienced by the average customer. The Company provides SAIDI data in Charts DLL-1 and DLL-3 of Mr. Louth's testimony, as well as in response to OCC-51 and -223.
- The SAIFI (System Average Interruption Frequency Index), which measures the frequency of outages. The Company provides SAIFI values in Charts DLL-2 and DLL-4 of Mr. Louth's testimony, as well as in reply to OCC-52 and -225.

In addition, in reply to OCC-284 the Company uses the total number of outages across its system to identify the reliability trends that it claims support its request for increased distribution investment. .

Q: What are the Company's projected costs of the refurbishment program?

A: The Company projects total distribution capital expenditures of $250 million per year, on average, over the period 2004–2007 (Chart DLL-12). The Company's filing does not clearly state what portion of the total will be spent on refurbishing the system, as opposed to improving power quality and accommodating load growth. The best approximation for refurbishment costs is the sum of what the Company calls "SAIDI improvement" and renewal of aging substation, overhead, and underground equipment. This is about 30% of the total or $75 annually.

Q: How much higher is this expenditure level than that of previous years?

A: Planned total expenditures are about $50 million more than the average in the last four years 1999–2002 and more than $100 million more than the average in the last fifteen years 1988–2002. The Company was unable to specify how much of this increase was attributable to the acceleration of its refurbishment program (see, for example, OCC-229).

Q: Has the Company offered adequate support for its proposed distribution rates?

A: No, for the following reasons:

- As noted above, the Company's justification for the requested increase is largely limited to a discussion of the vulnerability of its aging system and near-retirement of a large portion of its workforce. However, the Company does not explain how much of the cost increase is attributable to increased efforts in these two problem areas and how much to other lower-priority projects (such as improving power quality) `or to what the Company calls "franchise commitments." The Company provided total costs in response to OCC-54; they are reproduced and attached to this testimony as Exhibit____PLC-2.
- The company does not explain why so-called franchise commitments are so much greater than the historical expenditures for all distribution accounts combined. For 2003 and 2004, this category is estimated to be $120 million. This amount *alone* exceeds the total annual distribution expenditures for eleven of the last fifteen years—years that must have included other costs (such as those in CL&P's current "Acute Reliabi-

lity" category) in addition to what the Company now calls "franchise commitments" (Chart DLL-12; OCC-54).

- The Company's maintenance and workforce reductions and its past deferral of needed distribution system upgrades may have increased the future cost of distribution system replacements and maintenance.
- The ratepayers may have already paid for some of the planned refurbishments. To the extent that costs of the deferred investments were allowed in past rates, the Company should not be permitted to charge ratepayers for them again through current rates.
- The customer-outage data presented by the Company may not adequately support the Company's spending priorities or its claims about recent downward trends in reliability.
- The Company's modest SAIDI targets for the period 2004–2008 do not seem to match the level of expenditures it plans to make.
- The Company's rate request does not reflect any O&M savings resulting from the distribution refurbishments.
- The current expedited proceeding does not allow sufficient time to review the 1999–2003 construction program before it can be included in the rate base, which was required by the Department in Docket. No. 98-01-02 (Decision at 29).

Q: What rationale does CL&P provide for accelerating its system refurbishments?

A: Company Witness Dana Louth offers the following rationale:

- Much of the system is old and obsolete (Louth Direct at 3).
- Reliability improved when the Company increased its expenditures (Louth at 4).

- Recent outage data (SAIDI and SAIFI) show an increasing trend in equipment failures and associated customer outages (Louth at 5).

Q: What evidence do you have that the Company has deferred equipment upgrades and maintenance?

A: The following documents provided in response to discovery in the Northeast Utilities–Consolidated Edison merger case (Docket No. 00-01-11) note various budget-trimming measures.

The 1997 Budget Presentation reported that the Company had reduced the workforce where possible, and decided not to fund the following projects that were "deferrable but with serious consequences:"

- "Projects which provide relief for small contingency overloads/voltage problems during distribution auto-loop operation
- "Replacement of significant amounts of equipment identified as obsolete and in poor condition by field personnel….
- Multi-year obsolescence programs
- Strategic initiatives for distribution automation, planned replacement of obsolete equipment, craftworker attrition and [information-technology] enhancements." (OCC-181(b), Docket No. 00-01-11, at 17).

An internal May 20 1997 Status Report to the Corporate Affairs Committee of NU's Board of Trustees reported that the Company had reduced its workforce and deferred such activities as removing double poles, replacing old obsolete equipment, replacing direct buried cable, and inspecting and treating poles (OCC-173, Docket No. 00-01-11, at 8–9).

Q: How would deferral of equipment replacements and maintenance and the reductions in the workforce increase future distribution expenditures?

A: Deferred investment and maintenance could lead to increased equipment overloading and damage, resulting in premature aging and failure. Some of CL&P's planned equipment replacements may be needed to repair the damage done by past underinvestment.

Past workforce reductions may have also had cost consequences for the ratepayers. New workers require four or five years of formal and on-the-job training before they can replace retiring skilled staff. Therefore, the Company projects that it will need to hire 210 new workers over the next three years and six trainers by 2006, but that only 125 workers will retire by 2006 (Louth at 34–36). In addition, past workforce reductions may have resulted in the deferral of maintenance.

Q: Did the Company recognize that deferral of investment and maintenance has cost consequences?

A: Yes. The 1997 Budget Presentation recognizes that the decision not to fund major reliability projects would result in "risk of conductor damage," "excessive maintenance costs," and "[h]igher costs in future due to lack of investment now." (OCC-181(b) in the NU–Con Edison merger, Docket No. 00-01-11, at 17–18)

Q: Has the Company requested recovery of distribution-infrastructure-refurbishment expenditures in any prior rate case?

A: Yes. CL&P presented a similar proposal for an accelerated distribution-refurbishment program in Docket No. 98-01-02. The Company planned total capital expenditures averaging $240 million per year over five years, starting at $196 million in 1999 (Decision at 28). Currently the Company proposes $250 million per year over four years.

Q: Was the Company granted the cost recovery requested?

A: Yes. The Department found that the plan was "reasonable for planning purposes" and appears to have approved the inclusion in rates of the requested 1999 distribution construction expenditures (Decision at 28).

Q: Did the Company carry out the distribution construction plans it presented to the Department in Docket 98-01-02?

A: Only partly. It appears that actual expenditures fell far short of the plan presented to the Department.

- While the Department appears to have allowed the full $196 million of distribution construction expenditures in rates, only $166 million was actually spent (IR OCC-54).
- The Company told the Department that it planned to spend $1,202 million for distribution construction totaling over the period 1999–2003, or, on average, $240 million per year (Decision at 28). Over the five-year period, CL&P actually spent only a total of $1,022 million, $180 million less than planned for the period.
- The Company stated that its expenditures for replacing obsolete overhead equipment would reach $60 million by 2003. Now the Company estimates that it will spend only $13 million on the overhead infrastructure in 2003, and projects that expenditures in this category will not reach $60 million until 2006.
- In Docket No. 98-01-02, CL&P told the Department that its reliability expenditures on overhead plant would increase the percentage of wire that is covered from 34% in 1998 to 50% by 2003. The actual 2003 percentage is only 42% (EL-117). The Company has accomplished only half of its claimed goal.

Q: How does the Company interpret recent outage data?

A: In the Company's view, increases in SAIDI in the last two years indicate a deterioration in reliability that will continue in the absence of upgrades. (Louth at 8-9; OCC-222).

In his examination of the data on number of interruptions by cause, Mr. Louth (replying to OCC-284) also sees troubling trends in three of the important categories: equipment failure, tree-related incidents, and animal-related incidents:

> Three of the highest incident causes, animal/birds, tree related and equipment failure, are all trending negatively in most recent years, driving the overall negative performance trend. The Company's initiatives will address these trends.

The data provided by Mr. Louth are appended to this testimony as Exhibit____PLC-3.

Q: Has the Company demonstrated that there is an immediate need for an accelerated refurbishment program?

A: No. First, there are factors other than the aging of the system that may be driving the perceived decline in reliability. Second, the Company's past and future refurbishment expenditures may not be the most effective strategy for addressing these trends.

According to reliability data provided in response to OCC-225, all of the increase in SAIFI in the last two years can be attributed to equipment failure. It is difficult to understand why equipment failures have increased when the Company's distribution capital expenditures in 1999–2002 have been twice what they were before 1999.

Q: Do the data the Company presented demonstrate that the trends it has identified exist and that its planned refurbishments will reverse those trends?

A: The interpretation of this outage data is much more complicated than the Company suggests. For example,

- As Mr. Louth testifies, system SAIFI and SAIDI data (excluding major storms) suggest that equipment failures account for essentially the entire decline in reliability performance between 2000 and 2002 (Louth at 8, OCC-223, OCC-225). However, the Company's data on interruptions by cause indicate that equipment failure accounts for less than a quarter of the increase in the number of interruptions and an even smaller portion of the total number (OCC-284; reproduced in Exhibit____PLC-3).
- Tree-related incidents are much greater contributor than equipment failure, *alone* accounting for 25% of the total number of interruptions. Contrary to the Company's reading of the data, tree-related incidents declined through 2001 and only increased in 2002. That one-year increase is not likely to be the result of deterioration in the system; the bare wires are not getting barer over time. Indeed, the Company reports that 2002 was a bad year for minor storms, and that it had difficulty hiring tree-trimming contractors in 2002 (OCC-340). While continuing to cover bare wire would reduce tree-related outages, the Company has found in the past that this program was not cost-effective for laterals (Louth at 24–25).
- Almost 38% of increased outages from 2000 to 2002 were animal-related, of which about 90% were due to squirrels. The squirrel guards *may* be cost-effective in improving reliability, but the Company has not demonstrated that.[1]

[1]Conversely, considering the large number of squirrel-related outages, it is possible that most of the improved reliability from the Company's proposed investments would result from the squirrel guards, and that other expensive initiatives would have little effect. Once again,

Q: Do performance data indicate that the Company's recent and projected investments are prudent?

A: No. The Department needs to know whether the expenditures have been and will be effective and the best use of funds. A merely cursory look at outage data cannot substitute for careful consideration of program funding priorities.

Q: Has the Company evaluated the reliability benefits of each initiative in deciding on its spending priorities?

A: No. The Company does not appear to have evaluated the effect of its actual and proposed investments on reliability. For example, the Company has not analyzed the cost-effectiveness (and often even the cost) of direct-buried cable (OCC-231), lateral and backbone tree-trimming (OCC-261), or re-building mainline backbone circuits (OCC-228). Indeed, the Company claims to be unable to determine which distribution initiatives have consumed what part of the hundreds of millions of dollars it has spent in recent years (OCC-229).

The Company asserts that its distribution expenditures will meet its reliability goals, but is unable to estimate the benefit of any particular initiative (OCC-293). The expenditures should be tied directly to the targets, and the Company should be held responsible for meeting those targets.

Q: What sort of explanation of the benefits of past and proposed distribution initiatives would you expect, considering the magnitude of the expenditures proposed and the warning in Docket No. 98-02-01 that the 1999–2003 investments would be subject to review in this case?

CL&P has provided no basis for the Department to determine what expenditures are required or cost-effective.

A: I can give you an example of the information that the Company should have filed. Animal- and bird-related incidents account for 20% of the total number of interruptions in 2002. Suppose that squirrels are responsible for 50% of those incidents, the Company is planning to install squirrel guards on ⅔ of its equipment, and the equipment will be 100% effective. If this were the case, the squirrel guards alone would reduce total interruptions by 7%. The Company could convert that reduction in interruptions into improvements in SAIDI and SAIFI, based on the duration and average number of customers affected by animal-related outages. The Company has not presented this kind of analysis for any initiative.

Q: What performance targets do the Company propose?

A: Mr. Louth's direct provides targets for three reliability measures, but we only have historical data for comparison to the non-storm SAIDI goals, which are as follows (Chart DLL-9):[2]

	1999	2000	2001	2002	2004	2005	2006	2007
SAIDI	107	82	103	115	107	101	95	89

Q: Do these targets suggest that CL&P is confident in the effectiveness of its proposed refurbishment program?

A: No. The targets do not seem consistent with the proposed level of expenditures. Over the years 1999–2002, the start of the Company's major system refurbishment program, CL&P's SAIDI ranged from 82 to 115, averaging 102. The 2007 target is only a 12% improvement over the 1992–2002 average SAIDI. The relatively modest targets raise the question of whether the $300

[2]In response to OCC-283, the Company also provided SAIFI targets.

million refurbishment program is the best way to improve reliability on the CL&P system.

Q: Do these targets reflect the Company's expectations about the results of its construction programs?

A: Probably not. It appears that the Company's performance targets are based on what the Company believes customers want, not on an assessment of what the capital-expenditure program will accomplish.

Q: Does the Company anticipate the distribution refurbishment will result in O&M savings?

A: Yes. The Company expects O&M savings due to upgrades because the new equipment will be easier to maintain (OCC-231) but acknowledges that its revenue request reflects no O&M reductions.

Q: What is the Company's rationale for excluding O&M savings from its revenue request?

A: The Company (OCC-231) seeks to retain these savings to offset the revenue shortfalls it anticipates under its proposed Rate Plan:

> As explained in the prefiled testimony of Mr. Soderman, based on the Company's rate plan, even if the full amount of rate relief is granted, CL&P will not be able to recover its costs and earn its requested ROE, unless it can find ways to live within the revenues that the proposed rates produce. The savings from fewer outages, as well as savings associated with other initiatives, will be necessary in order to offset the effects of the earnings shortfall below the allowed ROE during the rate period.

Q: Is the Company's position valid?

A: No. The O&M savings should be included explicitly in the Company's rate case filing, for the following reasons:

- The Company is not entitled to some unspecified level of benefits of a large capital program that ratepayers are going to be paying for. If the Company has too much of a revenue shortfall, it can request rate relief.
- The Department needs to test the Company' assertion that its return will not be unreasonably high when these savings are added to the revenues requested in this proceeding.
- The Company should have developed estimates of O&M savings as part of its planning process. These estimates should therefore be readily available.
- The Department needs to know the projected costs and benefits of the refurbishment program in order to determine whether it is reasonable and necessary
- The Department needs to have the Company's analysis of O&M savings from refurbishments for its review of the prudence of the 1999-2003 investments.

Q: What issues should be addressed in an investigation of the rate recovery of the Company's distribution expenditures?

A: The investigation should address the following issues:

- the prudence of the CL&P's distribution capital improvements made in the period 1999-2003 as required by the Department in Docket No. 98-01-02 (Decision at 29);
- damages due to past reductions in the workforce and deferral of equipment upgrades and maintenance;
- the extent to which the ratepayers paid for deferred expenditures,

- determination of appropriate reliability targets and incentives, to be incorporated in a service-quality plan for the Rate Plan.[3]

IV. Implementing the Rate Cap

A. Initial Distribution Rates

Q: How does CL&P propose to reconcile the increase in distribution rates it proposes in this case with the rate cap required by G.L. Section 16-244c (b)(2)(B)?

A: In this proceeding, CL&P simply computes a total distribution rate that the Company asserts will provide a reasonable return on its distribution investment. Even assuming that the Department accepted all aspects of that computation, the distribution rate cannot be set in the manner the Company proposes.

Q: How should the distribution rates be set?

A: Public Act 03-135 requires that

> the total rate charged under the transitional standard offer, including electric transmission and distribution services, the conservation and load management program charge…, the renewable energy investment charge…, electric generation services, the competitive transition assessment and the systems benefits charge, and excluding federally mandated congestion costs, shall not exceed the base rates…in effect on December 31, 1996 ….

Of these cost items, the conservation-and-load-management-program charge and the renewable-energy-investment charge are set by statute. The competitive-transition assessment is largely determined by the repayment

[3]The Company did not include any service-quality plan in its proposal (OCC-345).

schedule for securitized bonds. The systems-benefits charge must recover specified costs, transmission rates are set by FERC, and the generation-services charge will be determined by market prices and the result of the various competitive acquisitions run by the utilities.

While the rate of recovery of some portions of the competitive transition assessment and systems-benefits charge may be subject to adjustment, any required reconciliation of costs to the rate cap must predominantly consist of reductions in distribution rates.

Q: Has CL&P proposed to meet the rate cap in the manner you have described?

A: No. As Company Witness Charles Goodwin explained in his testimony in Docket No. 03-07-01 (at 2),

> CL&P established the total revenue levels necessary to match the revenue requirements estimated for each of the following rate components: Distribution, Transmission, Competitive Transition Assessment ("CTA"), Systems Benefits Charge ("SBC"), Conservation and Load Management ("C&LM"), and Renewable Energy Investment Charge ("Renewables"). The difference (or residual) between the total computed TSO [temporary-standard-offer] revenues and these six revenue requirement levels constitutes the total Generation Services Charge ("GSC") the Company used to establish a base energy rate for the TSO service.

In other words, to ensure that it recovers all of its claimed distribution costs, the Company has proposed to take any shortfall out of the Generation Services Charge.

Q: How then does the Company propose to recover any generation costs that exceed the residual level of the Generation Service Charge?

A: As Mr. Goodwin explains (at 2),

> To the extent that the residual GSC fails to reconcile to the actual costs CL&P incurs to provide TSO generation supply services, the Company proposes that the difference would be collected or refunded, as appropriate, in the Energy Adjustment Clause ("EAC").

The Company proposes to recover some generation costs and all of its other costs, including distribution, under the rate cap, and to recover all other generation costs through the Energy Adjustment Clause. This approach would allow CL&P to recover all its allowed costs from ratepayers, just as it would have in a normal pre-restructuring rate case.

However, this is not a normal rate proceeding. The legislature, in establishing a rate cap for the next three years, has limited the Company's cost recovery to the costs that costs fit under the rate cap plus those costs explicitly exempt from the cap.

B. Federally Mandated Costs and the Generation Service Charge

Q: Is the Company's approach to setting the distribution rate allowed by the Public Acts 03-135 and 03-221?

A: No. As I noted above, the only exclusion allowed from the cap of 1996 rate levels is that of "federally mandated congestion costs," which are defined in Public Act 03-221 §2 as

> any cost approved by the Federal Energy Regulatory Commission as part of New England Standard Market Design including, but not limited to, locational marginal pricing and reliability must run contracts. (Subdivision (41) of subsection (a) of section 16-1 of the general statutes)

The obvious meaning of this definition is that it is intended to capture the incremental costs to Connecticut utilities of the congestion charges instituted under Standard Market Design. At this point, those costs are as follows:

- The difference between the locational marginal energy price in Connecticut compared to the pool-wide average marginal price that

Connecticut load-serving entities (in this case, the utilities) would have paid under ISO-NE's pre–Standard Market Design–pricing approach.

- Locationally allocated transmission charges and credits (minus the pool average for those charges and credit).
- The Connecticut-specific operating-reserve charges.
- Reliability must-run contracts required by Connecticut load and assigned to Connecticut by the ISO.

All other power-supply costs, including average pool energy prices, unforced capacity, reactive power, pool-wide operating reserves, and black-start capability are not federally mandated congestion costs. None of these charges are the result of congestion, and all predated the federally mandated Standard Market Design.

Q: How has CL&P defined congestion costs since the introduction of Standard Market Design, for the purpose of determining costs to be included in the Energy Adjustment Clause?

A: As the Company described in its filing in Docket No. 03-04-07, CL&P has been computing the "cost differential between the LMP [locational marginal price] at the suppliers' designated delivery points and the LMP in Connecticut" (Direct Testimony of Robert Baumann, Docket No. 03-04-07, at 3). CL&P (Baumann at 3) describes the "impact" of LMP on CL&P as resulting from "the manner in which congestion costs and PTF [pool-transmission-facility] losses are calculated, assessed and collected in New England." The Company computed the cost as "the sum of the hourly differentials in LMPs between the Connecticut delivery point and the suppliers' designated delivery points, multiplied by the appropriate load obligation for each supplier as settled in the day-ahead and real-time markets" (Baumann at 6).[4]

I attach as Exhibit____PLC-4 and Exhibit____PLC-5 excerpts from the direct testimony of Company Witnesses Shukerow and Baumann, respectively, in Docket 03-04-07. Those excerpts describe the effect of Standard Market Design on CL&P's generation costs, and CL&P's computation of its net costs.

Q: Does the legislative history support that reading of the legislation?

A: Yes. The Office of Legislative Research, in its Bill Analysis for SB 733 with Senate Amendment A (which excluded federally mandated congestion costs from the cap on rates), summarized this portion of the bill as follows:[5]

> The cap does not cover federally mandated costs related to congestion on the electric transmission system. The Federal Energy Regulatory Commission modified the pricing rules that govern the wholesale electric market, effective in March 2003, to require Connecticut consumers to pay for certain congestion-related costs that had previously been spread across New England.…

[4] In that docket CL&P apparently computed the cost of Standard Market Design as the price differential between Connecticut and the lowest-priced zone. (The computations themselves are confidential.) In fact, without Standard Market Design, the cost of serving Connecticut load would include an allocated share of pool-wide congestion costs, bringing the cost up to the average cost across the region. The details of the corresponding computation in the TSO will apparently be determined in Docket No. 03-07-10, and need not be considered in detail here.

[5] The analysis is on-line at http://www.cga.state.ct.us/2003/ba/2003SB-00733-R01-BA.htm. The online summaries and analyses provided by the Connecticut Office of Legislative Research are neither dated nor paginated. All online citations are as of September 25, 2003.

> **Federally Mandated Congestion Costs**
> Congestion on the electric transmission system increases the cost of providing service to congested areas, such as southwestern Connecticut (Fairfield County, most of New Haven County, and part of Litchfield County). Historically, these costs were spread across ratepayers throughout New England. However, a change in Federal Energy Regulatory Commission wholesale market rules has assigned the costs associated with southwestern Connecticut solely to Connecticut ratepayers since March 2003. In May 2003, DPUC allowed Connecticut Light & Power to temporarily pass on these costs to its ratepayers, resulting in a rate increase of approximately 8%.

The Bill Analysis for Public Act 03-221 describes the changes in that act as "technical" rather than substantive and summarizes the purpose of these provisions as follows:[6]

> PA 03-221 …. caps the rate for [transitional standard offer service] at the companies' 1996 rates, but excludes federally mandated congestion costs from the cap. This act specifies that these costs include locational marginal pricing and reliability "must-run" contracts. The former adjusts the wholesale cost of electric power geographically to reflect differing levels of transmission congestion within New England. The latter pay generators located within congested areas a premium for the power they produce.

In the house debate on Public Act 03-135 (May 27 2003) Representative Terry Backer who chairs the Energy and Technology Committee, described the intent of the bill.[7] In doing so, he clearly equated the exemption from the cap with the incremental cost of locational pricing, as follows:

- A "basic goal" of the bill is to "protect the consumer" from "price escalation."

[6] http://www.cga.state.ct.us/2003/olrdata/et/sum/2003SUM00221-R02HB-06428-SUM.htm.

[7] http://www.cga.state.ct.us/2003/trn/h/2003htr00527-r00-trn.htm.

- “We paid about 27% of that congestion cost.... standard market design now will require Connecticut not to pay 27% of those costs, as we used to pay, but we will now pay 100% of those costs.”
- “The cap cannot contain the 8% [the temporary Energy Adjustment Clause now in force, representing CL&P’s estimate of the locational costs of its suppliers since May]. That is a federally mandated charge that I cannot control in this legislation.”
- “Those line-loss and congestion costs …. these federally imposed costs were not contemplated when the original bill was done.”

He also stated that the administrative fee and incentive for power procurement will “go under the 11.1% cap.” So not only is the cost of power supply (except for specific federally mandated costs) constrained by the cap, but the utility incentive for procuring power must also fit under that cap.

Similarly, in introducing the bill in the Senate on May 21, 2003, Senator Tom Herlihy (ranking member of the Senate Energy Committee) equates the federally mandated congestion costs with the incremental effect of Standard Market Design.

> Every ratepayer in this state received an 8% increase in their bill this past month and that rate increase was due to a mandate from FERC...that said we can no longer socialize congestion costs over the New England grid, that they have to be focused on those states where the need is the greatest and unfortunately, Connecticut is one of those states. And so, no longer socializing those costs across all those states, we have seen an increase that has been federally mandated to our, essentially our electric bills. This will continue until we deal with the congestion problem in the State of Connecticut. And until we deal with it, we will have to pay these costs.[8]

[8]http://www.cga.state.ct.us/2003/trn/S/2003STR00521-R00-TRN.htm.

Q: Are the pool-wide costs also "approved by the Federal Energy Regulatory Commission as part of New England Standard Market Design?"

A: Yes. However, they are not related to congestion, unlike the examples included in the definition of federally mandated congestion costs: the locational portion of energy prices and the reliability-must-run contracts. All these costs were initially "approved by the Federal Energy Regulatory Commission" prior to the implementation of SMD.

If it meant for all power-supply costs to be included in this category, the legislature had no reason to the limit the category to *congestion* costs. The legislature would have been imposing a nearly meaningless rate cap had all power-supply costs (roughly half the total bill) been exempt from the cap.

Most importantly, if the legislature meant to exclude all generation costs from the rate cap (on the grounds that they are FERC-approved), CL&P would need to move the entire contents of its Generation Service Charge out of the rate cap and into the Energy Adjustment Clause. The Company has not proposed to do this; even CL&P does not seem to believe that the legislature meant to exempt all generation costs from the cap.

Q: How should the Company's request in this proceeding be modified to make it consistent in this regard with the statutory scheme?

A: The Department should clarify that the result of this proceeding will be maximum distribution rates, which will be reduced if necessary to accommodate the other cost categories under the rate cap. The only costs that are not subject to the rate cap are those mandated by federal decisions to manage congestion.

C. Adjustments of the Distribution Rate Over Time

Q: How does CL&P propose that the distribution rate change over time?

A: The Company requests a 1-percent annual increase in the distribution rate in 2005 and in 2006.

Q: How would CL&P reconcile those increases with the rate cap?

A: The Company has not been very specific, but it appears to anticipate that any net change in the non-generation costs, including the requested increases in the distribution rates, would result in offsetting changes in the Generation Service Charge. Any revenues lost in the Generation Service Charge would be recovered by increases in the Energy Adjustment Clause.

Q: Can the Department now schedule increases in distribution rates in the future?

A: No. The statutory rate cap limits the distribution rate for 2004–2006 to the residual of the 1996 rates, minus the other cost elements. The total of all rate elements (except for federally mandated congestion costs) may not exceed the rate cap.

Q: Would the distribution rate change over the 2004–2006 period?

A: Yes. The rate may need to be adjusted to reflect the actual initial level of the Generation Service Charge, probably before the beginning of 2004. The distribution rate may also need to change for the following factors:

- The adjustments in the transmission rate, as proposed by CL&P.
- Changes in the Competitive Transition Adjustment and System Benefits Charge.
- Changes in the Generation Service Charge after January 1, 2004.

Q: Why should the Generation Service Charge change between January 2004 and December 2006?

A: Standard and prudent practice for power-supply acquisition would include a set of solicitations for overlapping periods, to minimize the risk that any one purchase will be at a particularly inopportune time. In addition to the customers' direct cost of higher rates, concentrated purchases increase risks to power suppliers. If the single purchase is at a high-priced time, it may accelerate migration to direct access; if the purchase is at a time that turns out to be low-priced, few customers will leave the utility's generation service, and those that have left will tend to return.

Consequently, the seller faces an asymmetrical risk: if prices are high, the supplier will need to deliver lots of power; if prices are low, the supplier will have surplus to sell into a weak market. That asymmetry increases the prices suppliers must bid. If a bidder in 2004 for power to be delivered in 2006 knows that the utility's 2006 generation-service price will be some average of purchases in 2005 and 2006, as well as the purchase 2004, the migration risk will be mitigated.

Q: Has the legislature recognized this approach to power procurement?

A: Yes. In Public Act 03-135, the Legislature specifies how the standard service for 2007 and later years is to be procured.

> An electric distribution company providing electric generation services pursuant to this subsection shall mitigate the variation of the price of the service offered to its customers by procuring electric generation services contracts in the manner prescribed in a plan approved by the department. Such plan shall require that the portfolio of service contracts be procured in an overlapping pattern of fixed periods at such times and in such manner and duration as the department determines to be most likely to produce just, reasonable and reasonably stable retail rates while reflecting underlying wholesale market prices over time. The portfolio of contracts shall be assembled in such manner as to...guard against... improvidence...and secure a reliable electricity supply while avoiding unusual, anomalous or excessive pricing. G.L.c.16-244(c)(3)

This language does not govern the acquisition of the generation services during the period of the Transitional Standard Offer, but the same concepts are applicable and should be applied.

Q: Does this conclude your testimony?

A: Yes.

Exhibit PLC-1

PAUL L. CHERNICK

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SUMMARY OF PROFESSIONAL EXPERIENCE

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

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

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

EDUCATION

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

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

HONORS

Chi Epsilon (Civil Engineering)

Tau Beta Pi (Engineering)

Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

PUBLICATIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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"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;

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

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"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.

112.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.

113. **Ohio PUC** 91-635-EL-FOR, 92-312-EL-FOR, 92-1172-EL-ECP; Cincinnati, City of Cincinnati, April 1993.

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

114. **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.

115. **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.

116. **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.

117. **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.

118. **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.

119. **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.

120. **MDPU** 94-49, Boston Edison integrated resource-management plan; Massachusetts Attorney General. August 1994.

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

121. **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.

122. **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.

123. **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."

124. **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.

125. **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.

126. **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.

127. **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.

128. **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.

129. **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.

130. **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.

131. **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.

132. **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.

133. **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.

134. **North Carolina Utilities Commission** E-2, Sub 669. December 1995.

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

135. **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.

136. **Ohio PSC** 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.

137 **Vermont PSB** 5835; Vermont Department of Public Service. February 1996.

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

138. **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.

138 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.

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

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

140. **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.

141. **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.

142. **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.

143. **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.

144. **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.

145. **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.

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

Performance incentives proposed for the Boston Edison company.

147. **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.

148. **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.

149. **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.

150. **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.

151. 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.

152. 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.

153. 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.

154. 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.

155. 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.

156. 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.

157. 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.

158. 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.

159. **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.

160. **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.

161. **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.

162. **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.

163. **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.

164. **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

165. **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.

166. **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.

167. **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.

168. **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.

169. **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.

170. **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.

171. **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.

172. **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.

173. **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.

174. **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.

175. **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.

176. **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.

177. **MEFSB** 97-4; MMWEC gas-pipeline proposal; Town of Wilbraham, Mass. June 2000.

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

178. **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.

179. **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.

180. **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.

181. **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.

182. **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.

183. **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.

184. 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.

185. 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.

186. New Jersey BPU EX1050303; 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.

188. NY PSC 0-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.

187. MDTE 01-56, Berkshire Gas Company; Massachusetts Attorney General. October 2001.

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

188. 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.

189. 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.

190. 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.

191. **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.

192. **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.

194. **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.

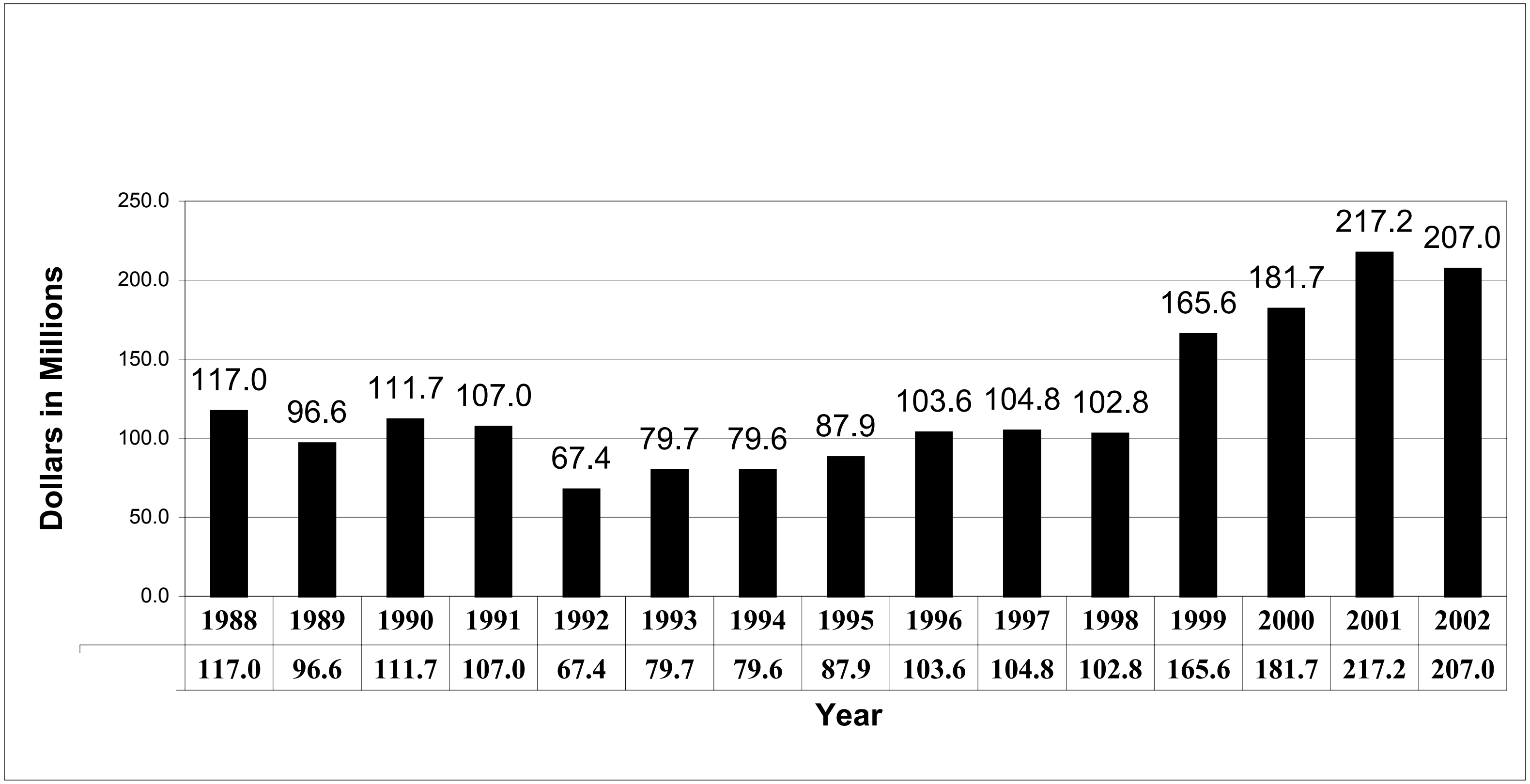
195. **Ontario EB** RP-2002-0120; Review of transmission-system code; Green Energy Coalition. October 2002.

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

196. **New Jersey BPU** ER02080507; Jersey Central Power & Light rates; N.J. Division of the Ratepayer Advocate. December 2002.

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

Exhibit PLC-2:
CL&P Distribution Capital Expenditures, 1988–2002



Source: Response to OCC-54

Exhibit PLC-3:
CL&P Outage Data, 1998–2002

	# Interruptions by Cause				
CAUSE	**1998**	**1999**	**2000**	**2001**	**2002**
POWER SUPPLY	5	24	9	0	26
PLANNED	50	89	83	65	118
CUSTOMER CAUSED	18	24	22	31	31
ANIMALS/BIRDS	2313	2499	1851	2386	2668
LIGHTNING	1321	576	941	934	673
OVERLOAD	318	707	352	666	625
TREE RELATED	3012	3216	2912	2735	3435
VEHICLE/ACCIDENT	368	443	424	454	456
CONTACT WITH FOREIGN OBJECT	199	204	152	231	171
EMPLOYEE OPERATING ERROR	66	82	89	132	71
OTHER	638	1181	1126	1183	1082
EQUIPMENT FAILURE OVERHEAD	664	492	442	423	624
EQUIPMENT FAILURE UNDERGROUND CABLE	109	110	93	101	126
EQUIPMENT FAILURE DIRECT BURIED	500	472	382	461	457
EQUIPMENT FAILURE TRANSMISSION	12	1	1	43	42
EQUIPMENT FAILURE SUBSTATION	16	22	26	46	41
EQUIPMENT FAILURE TRANSFORMER	412	288	288	369	427
UNKNOWN	1156	1083	938	1051	1215
TOTAL SYSTEM	11177	11513	10131	11311	12288

Exhibit PLC-4:
Excerpts from Shukerow Direct in Docket No. 03-04-07

EXHIBIT A

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL

DOCKET NO. 03-04-07

APPLICATION OF THE CONNECTICUT LIGHT AND POWER COMPANY CONCERNING RECOVERY OF SMD-RELATED COSTS FOR MARCH 1, 2003 THROUGH DECEMBER 31, 2003

TESTIMONY OF

JAMES R. SHUCKEROW, JR.

ON BEHALF OF

THE CONNECTICUT LIGHT AND POWER COMPANY

APRIL 22, 2003

III. PRE-SMD TREATMENT OF CONGESTION COSTS AND PTF LOSSES

Q. What are "congestion costs" and how were they calculated and assessed prior to March 1, 2003?

A. Prior to March 1, 2003, the wholesale electricity market in New England contained a single spot market for the sale of electric energy and ISO New England Inc. ("ISO-NE") calculated a single hourly energy clearing price ("ECP"). In essence, the hourly ECP was determined by stacking bids received from generators throughout New England from the lowest to the highest cost to supply energy in that hour, and setting the ECP equal to the highest bid in the resulting stack needed to satisfy the electric load on the system in that hour. Generators with bids equal to or less than the ECP were directed by ISO-NE to dispatch, and in return they received compensation equal to the ECP. When there was a constraint on the New England transmission grid that prevented the physical delivery of electric generation that was bid at a price equal to or lower than the ECP, ISO-NE would dispatch local generation at additional higher costs. The owners of this higher-cost generation received compensation equal to their bid price, but that bid price was not used to set the ECP. The additional costs incurred to compensate the owners of this higher-cost generation were socialized and passed on to all consumers in New England as a "congestion" cost.

Q. What were the congestion costs for New England during calendar year 2002?

A. For 2002, the billed congestion costs across New England were on the order of $110 million. Connecticut's socialized share was on the order of $27 million.

Q. What are PTF losses?

A. PTF are those transmission facilities in New England that meet the definition of "Pool Transmission Facilities" in the Restated New England Power Pool ("NEPOOL") Agreement. Generally speaking, PTF are the transmission facilities of NEPOOL members with ratings of 69 kV or above that are looped facilities needed for the movement of bulk power in New England. PTF losses are electricity losses caused by resistance when electric energy is transferred from one point to another along the PTF. Prior to March 1, 2003, costs resulting from PTF losses were uniformly priced throughout New England.

Q. What were the PTF losses for New England during calendar year 2002?

A. In 2002, PTF losses equaled approximately 1% of the total load in New England.

IV. IMPACT OF SMD ON CONGESTION COSTS AND PTF LOSSES

Q. What is SMD?

A. On July 15, 2002, NEPOOL and ISO-NE jointly filed with the Federal Energy Regulatory Commission ("FERC") a proposal to replace the structure and design of the then-existing New England electricity market with SMD. The SMD proposal was modeled after the market design currently operated by PJM Interconnection, L.L.C. FERC issued orders in October and December 2002 that approved the SMD proposal and it was implemented on March 1, 2003.

Q. Did SMD change the manner in which congestion costs and PTF losses are calculated, assessed and collected?

A. Yes. The nature of the costs for congestion and PTF losses fundamentally changed as a result of SMD's implementation of a system of LMP.

Q. Please explain the impact of LMP.

A. Under LMP, different prices are identified at various points on the New England electric grid to reflect the value of generation at those points. LMP implemented four major changes to the manner in which congestion costs and PTF losses are calculated, allocated and recovered.

First, under LMP the New England region has been divided into eight "Load Zones" and approximately 900 "Nodes." Each New England state (other than Massachusetts) comprises a separate Load Zone, with Massachusetts being divided into three Load Zones. Each Node is a location on the transmission grid as designated by ISO-NE, and there are approximately 200 Nodes in the Connecticut Load Zone. For each Node, ISO-NE calculates a separate hourly price, which is known as the LMP or "locational marginal price" for that Node. The LMP includes the price of energy, congestion and PTF losses at that Node. For any hour when there are no transmission constraints within New England, the hourly LMPs will vary only due to PTF losses. However, for any hour in which there are transmission constraints, LMPs will also vary due to congestion.

Second, LMP changed the method for compensating all of the generators operating within a constrained area. Prior to the implementation of SMD, each owner of higher-cost generation that was directed by ISO-NE to operate out-of-merit order to alleviate congestion received compensation equal to its bid price, but that bid price was not used to set the ECP. In contrast, under SMD, an out-of-merit generator running because of constraints in a congested area will establish the LMP for that area, and that out-of-merit generator as well as each generator operating in that congested area will be entitled to this increased LMP. By way of example, if the unconstrained LMP was $25 per MWh, but constraints require an out-of-merit generator in the area to operate and its cost to operate is $100 per MWh, the LMP in that area would be set at $100 per MWh, and all generators operating in that area (not just the out-of-merit generator) would be entitled to $100 per MWh as adjusted for PTF losses.

Third, LMP changed the methodology for recovering congestion costs. Prior to the implementation of SMD, congestion costs for New England were socialized among all consumers in New England. In contrast, as of March 1, 2003, the socialization of these costs has ended. All costs attributable to transmission constraints in the Connecticut Load Zone will be paid for solely by consumers in Connecticut.

Fourth, LMP changed the manner in which PTF losses are allocated and collected among participants in the New England energy market. Prior to March 1, 2003, the cost of PTF losses was socialized throughout New England and was generally equal to about 1% of New England load. The cost of these losses did not vary based on delivery point. Under SMD, however, the cost of PTF losses is reflected as a component of the LMP and varies by location. The physical loss calculation has largely been replaced by economic price signals.

Q. What is the anticipated cost impact of LMP on CL&P during 2003?

A. Connecticut is expected to shoulder a substantial portion of the costs associated with LMP for two reasons. First, southwest Connecticut is one of the two most constrained regions in New England. Second, due to the significant amount of energy imports into Connecticut, the PTF loss component of the LMP is expected to be higher. The result will be higher costs for PTF losses in Connecticut. As a result, the LMPs for Connecticut are likely to be higher than elsewhere in New England, which will result in higher costs to Connecticut.

The pre-filed testimony of Mr. Robert A. Baumann, Director-Revenue Regulation & Load Resources for CL&P, describes the cost impact on CL&P for 2003 resulting from LMP and its supply contracts. ISO-NE recently estimated that under LMP, congestion costs for New England in 2003 will range between $50 million to $300 million, with the majority of these costs expected to be attributable to Connecticut due to severe constraints in the southwest part of the State.

Exhibit PLC-5:
Excerpts from Baumann Direct in Docket No. 03-04-07

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL

DOCKET NO. 03-04-07

APPLICATION OF THE CONNECTICUT LIGHT AND POWER COMPANY
CONCERNING RECOVERY OF SMD-RELATED COSTS FOR MARCH 1, 2003
THROUGH DECEMBER 31, 2003

TESTIMONY OF

ROBERT A. BAUMANN

ON BEHALF OF

THE CONNECTICUT LIGHT AND POWER COMPANY

APRIL 22, 2003

In Section III of my testimony, I describe CL&P's LMP differential costs for March 2003. In Section IV, I discuss CL&P's cost recovery proposal in more detail. In Section V, I describe the manner in which each of CL&P's suppliers is operating under their contracts subsequent to the implementation of SMD. Attachments RAB-1 through RAB-6 provide supporting detail.

III. CL&P's LMP-RELATED COSTS FOR 2003

Q. What impact has LMP had on CL&P?

A. CL&P's Application in this proceeding and the pre-filed testimony of Mr. James R. Shuckerow, Jr., explain that LMP was implemented on March 1, 2003 and it had a profound impact on the manner in which congestion costs and PTF losses are calculated, assessed and collected in New England. Because the agreements with CL&P's standard offer suppliers enable the suppliers to designate any delivery point on the New England grid to deliver their portion of the standard offer power, there is a resulting cost differential between the LMP at the suppliers' designated delivery points and the LMP in Connecticut.

Q. What were CL&P's LMP differential costs for March 2003?

A. As shown in RAB-3, for March 2003, the differential between the LMPs at the delivery points designated by CL&P's standard offer suppliers and the LMP in Connecticut resulted in a cost of approximately $15.5 million for CL&P. For the month of March, the $15.5 million LMP differential costs were primarily attributable to the losses component of LMP. Additional detail explaining the calculation of the $15.5 million figure is provided in attachments RAB-3 to RAB-6 to my pre-filed testimony.

Q. How did you calculate this $15.5 million amount?

A. It is the sum of the hourly differentials in LMPs between the Connecticut delivery point and the suppliers' designated delivery points, multiplied by the appropriate load obligation for each supplier as settled in the day-ahead and real-time markets. These amounts are derived from the billing determinants associated with the ISO-NE monthly billing process. The specific calculation of the LMP differential costs are reflected in attachments RAB-3 to RAB-6.

Q. Has CL&P already paid these LMP-related costs for March 2003?

A. CL&P's LMP costs for March 2003 will be paid by the end of April or during the first week in May to ISO-NE and/or the appropriate suppliers, depending on the selected delivery points and the arrangements with each supplier.

IV. CL&P'S COST RECOVERY PROPOSAL

Q. How does the Company propose to recover its LMP costs for 2003?

A. Commencing with the Company's LMP differential costs incurred in March 2003, CL&P proposes that the excess GSC revenue for that month be applied to those costs. To the extent that the excess revenue is insufficient to fully cover those costs, the additional amount due for March would be recovered in an EAC charge in May billings. Under this proposal, the Company requests that $5.88 million of excess GSC revenue in March 2003 be applied to the Company's