DOCKET NO. 11000

APPLICATION OF HOUSTON	§	
LIGHTING & POWER COMPANY	§	PUBLIC UTILITY COMMISSION
TO AMEND CCN FOR THE	§	
DUPONT PROJECT GENERATION	§	
UNIT	§	OF TEXAS

TESTIMONY OF

PAUL CHERNICK

RESOURCE INSIGHT, INC.

TESTIFYING ON BEHALF OF
DESTEC ENERGY, INC.

SEPTEMBER 28, 1992

DOCKET NO. 11000

APPLICATION OF HOUSTON	§	
LIGHTING & POWER COMPANY	§	PUBLIC UTILITY COMMISSION
FOR A CERTIFICATE OF	§	
CONVENIENCE AND NECESSITY	§	OF TEXAS
FOR THE DuPont PROJECT	§	

DIRECT TESTIMONY OF

PAUL L. CHERNICK
President
Resource Insight
Boston Massachusetts

ON BEHALF OF

DESTEC ENERGY, INC.

September 28, 1992

TABLE OF CONTENTS

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

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

A: I am Paul L. Chernick. I am President of Resource Insight, Inc., 18 Tremont Street, Suite 1000, Boston, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an S.B. degree from the Massachusetts Institute of Technology in June 1974, from the Civil Engineering Department, and an S.M. 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 over 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, and from 1986 as President of Resource Insight, Inc. (formerly PLC, Inc.). In my current position at Resource Insight, I have advised a variety of clients on utility matters. My work has considered, among other things, the need for, cost of, and 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; and the valuation of environmental externalities from energy production and use. My resume is attached to this testimony as

PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified approximately one hundred times on utility issues before various regulatory, legislative, and judicial bodies, including the Massachusetts Department of Public Utilities, the Massachusetts Energy Facilities Siting Council, the Vermont Public Service Board, the New Mexico Public Service Commission, the District of Columbia Public Service Commission, the New Hampshire Public Utilities Commission, the Connecticut Department of Public Utility Control, the Michigan Public Service Commission, the Maine Public Utilities Commission, the Minnesota Public Utilities Commission, the South Carolina Public Service Commission, the Maryland Public Service Commission, the Florida Public Service Commission, the Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. A detailed list of my previous testimony is contained in my resume.

Q: Have you testified previously on externalities?

A: Yes. I have testified extensively on externalities valuation in Massachusetts for the past two and a half years on behalf of the Boston Gas Company. My testimony in Vermont Public Service Board Dockets 5270 and 5330 also included externalities. Additionally, I have testified or prepared comments on externalities valuation and incorporation in California, Ontario, Illinois, Maryland, and Vermont and have worked on the Conservation Law Foundation/New England Electric externalities collaborative and in the New York externalities study, on behalf of the New York State Energy Research and

Development Administration.

Q: Have you authored any publications on externalities?

A: Yes. I have authored about a dozen publications, listed on my resume, on externalities valuation. I have presented several of these papers at national conferences. I was also one of the principal technical consultants and authors of the Pace University study, *The Environmental Costs of Electricity*.

II. PURPOSE OF TESTIMONY AND CONCLUSIONS

Q: What is the purpose of your testimony?

A: My testimony is intended to:

- describe how Houston Lighting and Power (HL&P) has failed to include "a reasonable estimate of externalities" for the DuPont project,
- describe how HL&P could have included externalities into resource comparisons in a consistent and orderly fashion that would improve utility resource decisions,
- explain why HL&P's externality analyses fail to fully account for resource externalities, and
- explain why HL&P's analysis of the DuPont/HL&P project is not consistent with least-cost planning.

Q. Could you summarize your conclusions?

A. I have three fundamental conclusions. First, HL&P has failed to make a reasonable estimate of externalities. HL&P's study does not provide the Commission or anyone else with sufficient information to make any reasonable evaluation of the externalities such that it could be used to adequately evaluate the DuPont Project from a planning or benefit analysis perspective. Second, the DuPont Project will not have anything like the environmental benefits claimed when a complete analysis is done and the DuPont Project is likely to be found to have a more adverse impacts on the environment than construction of a combined cycle plant, the extension of existing cogeneration contracts, or other alternatives in the time frame suggested. Third, HL&P has not correctly applied a least cost planning methodology.

III. HL&P REVIEW OF EXTERNALITIES

Q: Have you reviewed HL&P's treatment of externalities in this docket?

A: Yes. I have reviewed portions of the CCN Application, particularly Study #6, the testimony of Messrs. Naeve, Feith, and Griffey; and numerous RFI responses.

Q: Has HL&P produced and used "reasonable estimates" of externalities?

A: No. HL&P has not made a serious attempt to value externalities in its analysis of the DuPont project, in terms of the approaches it used in selecting values, or the actual values selected. HL&P applied its externality values incorrectly in evaluating the DuPont project by overstating the emissions reductions attributable to that project. HL&P also failed to systematically compare the combined economic and environmental effects of the DuPont Project to those of attractive alternatives. In all three of these areas, HL&P's analysis is incomplete and flawed, falling far short of the state of the art or of good utility practice.

Q: Would the public interest be served by Commission acceptance of the HL&P analysis as a "reasonable estimate" of the external costs of the DuPont project?

A: No. If the Commission accepted this feeble and misleading effort as a "reasonable estimate," neither HL&P nor other Texas utilities would have any incentive to reach the level of current good practice in externality valuation, let alone attempt to advance the debate. Significant benefits to ratepayers and the

State as a whole would be lost by the failure to properly reflect all costs--external as well as internal--in resource planning.

Q: How is the rest of your testimony organized?

A: Each of the four points above will be addressed in turn. Section IV discusses the derivation and use of externality values in utility resource planning. Section V explains the problems in HL&P's externality analyses. Section VI considers HL&P's approach in the context of least-cost planning.

Since the question in this docket is limited to whether HL&P's treatment of the externalities is reasonable, I will not attempt an exhaustive review of theory and practice in externality valuation. Additional detail on these subjects can be found in the forthcoming report, *From Here to Efficiency: Securing Efficiency Resources*, prepared by Resource Insight for the Pennsylvania Energy Office.

IV. INCLUDING EXTERNALITIES IN UTILITY RESOURCE PLANNING

Q: Please define the term externalities and explain it in the context of utility planning.

A: Externalities, or external costs, are generally defined as those costs not borne by the persons who impose them. In contrast to the internal costs paid by the person who decides to create them, externalities are paid by someone else. An obvious example in the utility context is the allocation of the costs of burning fuels. The utility pays the price of the fuel and pays for disposal of any residue, but does not pay the costs imposed by the pollutants that leave the power plant stack, including health and aesthetic effects, damages to ecosystems, and so on.

This usual definition of externalities raises some semantic issues in the utility context. For example, does the utility "bear" costs that it flows through to ratepayers? Do internal costs include all costs that affect revenue requirements, or only those that affect shareholders earnings? For that matter, is it more realistic to view utility managers as distinct from shareholders, weighing only costs and benefits borne by management? On the other hand, is it proper to treat environmental impacts that happen to fall on utility shareholders and ratepayers as internalized?

To avoid these confusions, it is easier to define environmental externalities as all environmental costs that are not included in the direct costs used in comparing utility resource options. In standard utility practice, all costs that appear in revenue requirements calculations are internalized; other energy service costs to customers (such as for DSM) are sometimes included. All other costs are externalities.[1]

Q: Why should the Commission consider externalities, and particularly environmental externalities, in this docket?

A: There are several reasons for doing so.

First, the Commission's Order approving the Notice of Intent for the DuPont Project requires that HL&P make a "reasonable estimate" of externalities. This docket will decide whether HL&P has met that test.

Second, the Texas Legislature has explicitly given the Commission the responsibility of considering environmental costs. According to the Public Utility Regulatory Act, §54 requires that, in reviewing applications of certificates of

---

[1]My testimony will only discuss environmental externalities. Similar approaches can be extended to economic and social externalities.

convenience and necessity, the Commission consider "such factors as community values, recreational and park areas, historical and aesthetic values [and] environmental integrity" (TEX. REV. CIV. STAT. ANN., art. 1446c).

Third, the Commission has primary or exclusive responsibility for reviewing many utility resource decisions that have important environmental implications. Environmental agencies cannot easily influence utility resource decisions beyond requiring additional pollution control measures or rejecting a project. Only utility regulators can structure utility resource decisions to include non-market costs in comparing resources options. Utility regulators understand utility planning, costing, operation, and system interactions at a level of detail environmental regulators would be able to copy only at high costs.

Fourth, utility regulators have responsibility for the planning and acquisition decisions of electric and gas utilities, which collectively represent about one-fourth of energy consumed in the U.S. and a large fraction of air pollutant and greenhouse gas emissions. Utilities are responsible for about two-thirds of total U.S. SO_2 emissions, one third of total NO_x emissions, one-quarter of total CO_2 emissions, 30% of total mercury emissions,[2] as well as significant fractions of other toxic emissions.

Fifth, utility regulators have a responsibility to future ratepayers to consider external effects, since today's externality may be tomorrow's internalized cost, through pollution taxes, requirements for additional controls,

[2]Neme, 1991, and *Electric Utility Week*, September 7, 1992, summarizing a report by Clean Water Action.

allowances and offsets, requirements, and other mechanisms. Resources with high external costs impose additional risks on ratepayers for decades into the future.

A. Approaches to Reflecting Externalities in Utility Resource Decisions

Q: How can externalities be included in the evaluation of utility resource options?

A: The relevant external effects must first be identified. A mechanism must then be adopted for incorporating the level of those effects in utility decisions. A number of approaches have been suggested, which can be divided into four groups:

- reduce or eliminate external costs, removing any need for utilities or their regulators to consider externalities at all, except for their effect on control costs;
- internalize all external effects, so that all resource costs are stated in dollars;
- reflect external costs in non-monetary terms in the evaluation of resource options; and
- monetize externalities and add them to direct internal costs in the evaluation of resource options.

Q: Are all of these approaches viable?

A: No. As I have discussed elsewhere (Chernick and Birner, 1992), I believe that as of today only monetization will fully and efficiently reflect external costs in utility resource planning and acquisition. For most applications, externalities must be monetized if utilities and the PUC are to minimize the cost of meeting any given level of environmental quality, or maximize the environmental benefit of a given level of direct utility costs.

HL&P uses the monetization approach in its Study #6 and the testimony of Mr. Griffey. The Commission itself appears to have expected externalities to be treated in economic terms, i.e., monetized. Given this convergence, I will deal in this testimony only with monetization.

B. Methods for Monetizing Externalities

Q: Can reasonable monetary values of externalities be determined?

A: Yes. As discussed in Chernick and Caverhill (1992) the principal approaches are damage costing and regulatory cost of control. As the state to the art advances, both of these approaches will continue to improve, other approaches may emerge, and estimates may change. Nonetheless, externality valuation is sufficiently mature that either of these methods can produce values that are useful in comparing options.

Damage costing is generally undertaken by environmental regulators, in the process of setting allowed emissions. Utility regulators generally lack the resources to deal with the complexity of this approach, in terms of data requirements; modelling of pollutant transport, chemistry, and dose-response relationships; and valuation of health, aesthetic, and ecosystem effects.

Rather than ignoring or repeating the determinations of environmental regulators, utility regulators can generally rely on the environmental regulators to determine the benefits of pollution control. This is the basis of the regulatory cost-of-control (RCC) approach used by utility regulators in four states to evaluate environmental externalities. In the RCC approach, utility regulators use the values of externalities published by environmental regulators, or implied by their regulatory actions.

For some environmental externalities, damage costs are irrelevant to utility regulatory decisions, because reductions in emissions due to utility resources decisions will not reduce total emissions. When environmental regulators are committed to an environmental goal, such as a fixed reduction in emissions or in ambient pollution levels, reductions in utility versus other source emissions are merely a tradeoff. Reductions in emissions from utility sources will result in fewer reductions from other sources that would otherwise have been required to meet the goal. The benefits of the reduction are thus not improved environmental quality, but reduced compliance costs, either for the utility itself or for other emitters in the jurisdiction, many of whom will be customers of the utility. Clearly, only the RCC method can measure the cost of pollutants regulated to meet a goal.

Q: Can the RCC method be extended to currently unregulated pollutants, such as CO_2 and other greenhouse gases?

A: Yes. In those situations, the PUC will have to estimate the expected level of emissions cap, and the corresponding cost of control.

Q: Can regulatory costs of control be determined with precision?

A: The precision of RCC estimates varies with the quality of data available, but the estimates are generally precise enough to be useful. Like any other prediction about the future, from load growth to fuel prices, the required costs of control are subject to some uncertainty. For most pollutants, we have information on the costs of controls currently required in the relevant area (e.g., the Houston CMSA); for many (such as ozone precursors), we also have estimates of the costs of complying with new regulations. For some unregulated externalities, such as CO_2, we have estimates of the costs of various levels of reduction, and of the reductions that would be necessary to limit the environmental effects to a potentially tolerable range. Uncertainties in externality values can be addressed explicitly using approaches similar to those used in dealing with the uncertainties in other inputs. Thus, enough information is available to make reasonable and informed judgments, as regulators do with respect to other predictions.

Some observers who do not understand the RCC method are confused by the fact that a number of control measures are typically required for each pollutant, with a wide range of costs. The RCC method uses only the marginal cost of control, just as the evaluation of new supply resources uses only the marginal (or decremental) dispatch costs of existing resources. The fact that some controls on NOx may cost only $200/T has no bearing on the RCC so long as SCR is required on some power plants at $6,000/T, just as the fact that the marginal running cost of South Texas is less than 1¢/kWh has no bearing on the benefit of a new resource that will be available when HL&P would otherwise be running combustion turbines at 3¢/kWh.[3]

Q: Is there any role for externality damage costing in utility regulation?

A: Yes. Damage costing may be useful for valuing social and economic externalities. Damage costing can also be useful where pollutants are not regulated or the cost of control is not easily determined. See Chernick and Caverhill (1992).

---

[3]On the fuel forecasting side, the cost of existing oil wells that produce at $2/bbl is irrelevant to estimating future market-clearing prices when marginal supplies cost $20/bbl.

C. HL&P Arguments Against Including Externalities in Planning

Q: Does HL&P agree that externalities should be included in the evaluation of utility resources?

A: No. The direct testimony of Mr. Naeve (pp. 17-21) presents HL&P's policy arguments.

Q: Please summarize and respond to Mr. Naeve's arguments on the inclusion of externalities in utility resource planning.

A: A number of Mr. Naeve's assertions are vague and difficult to interpret. I will only respond to the most coherent of Mr. Naeve's assertions.

First, Mr. Naeve asserts that "there are still a host of issues to be resolved by the scientific community before any attempt at quantification can be considered meaningful or appropriate" (p. 17, lines 16-19). This assertion is clearly irrelevant to the emissions that must be controlled to reach specified ambient levels (i.e., NO_x and VOCs), since estimates of damages are irrelevant once emission levels are fixed. The argument is also very weak for pollutants for which the TACB has determined reasonable control costs (e.g., particulates, SO_2). More generally, Mr. Naeve appears to suggest that any uncertain number should be set to zero; this is obviously an absurd position, and HL&P does not apply it to forecasts of fuel prices or load growth.

Second, Mr. Naeve notes that "the potential for poor decision making and illogical conclusions is great if only one of these estimates misses its mark too widely" (p. 17, lines 23-25).[4] I agree that, in externality valuation, as for other

[4]It is not clear what he means by "illogical conclusions" or why he refers to "only one" estimate.

inputs to the planning process, HL&P should strive for the best available estimates, and avoid the "rank speculation" Mr. Naeve abhors (p. 19, line 17). As I will discuss, HL&P has not attempted to obtain and use the best available estimates.

Third, Mr. Naeve asserts that while external effects produce costs, "associated benefits to society also exist" (p. 17, lines 27-28). While there are some benefits of pollution (e.g., nitrogen fertilization of crops, enhanced sunsets), the costs have clearly been determined to outweigh the benefits, since controls are required by the "elected representatives" (and their environmental agencies) to whom Mr. Naeve would refer these issues (p. 19, line 4). Mr. Naeve's conclusion that "the assumption that the net impacts of externalities is zero may be quite appropriate" (pp. 17-18) is obviously incorrect for all regulated air pollutants. As I discuss below, it is also a flawed conclusion with respect to CO_2.

Fourth, Mr. Naeve states that "This Commission is entrusted with ensuring that customers pay for only the prudently incurred, direct costs associated with providing them electric service" (p. 18, lines 14-15). I agree, although the Commission has other responsibilities, including environmental. HL&P should not charge its customers for the values of externalities HL&P imposes on them and on other parties.

Fifth, Mr. Naeve asserts that "the only resulting certainty [from externality valuation] is that there will be higher electric rates" (p. 18, lines 22-23). Mr. Naeve ignores the benefits from evaluating externalities and presents no evidence that the necessary result is higher rates.

Sixth, Mr. Naeve notes that "the most cost effective targets for [emissions] reduction" may be outside the utility industry, such as in motor vehicles (pp 19-20). The costs of NO_x controls I estimate below assume that all cost-effective identifiable controls are required in all sectors. If there are additional cost-effective controls for regulated pollutants, that may result in a reduction in the marginal cost of controls required in the Houston area, the TACB is the forum for their consideration. Otherwise, this point is irrelevant to the Commission's determination of externality values.

Seventh, Mr. Naeve suggests that HL&P is concerned that it will want to mitigate carbon emissions in order to build coal plants and that the Commission will not allow recovery of mitigation costs (p. 20). He then asserts that, if HL&P were not allowed to recover the cost of planting trees in Guatemala, the Commission should not mandate the inclusion of externalities in the resource selection process (p. 20, lines 1-2). Mr. Naeve does not demonstrate that the offsets he discusses are an appropriate substitute for externality valuation. Offsets raise complex issues of marginality and reliability, and are beyond the scope of this proceeding given the Commission's Order in the NOI. Mr. Naeve is also incorrect in asserting that the Commission's potential rejection of his preferred offsets would invalidate the use of monetized externalities; the two issues are entirely separate, and Mr. Naeve shows no connection between them.

D. Monetized Externality Values in Other States

Q: Have other states monetized externalities in resource planning?

A: Several states have explicitly valued externalities since 1989, when the New York PSC required Orange and Rockland Utilities to incorporate environmental costs totalling 1.4 cents/kWh for a new coal plant. Since that time, New York has extended its valuation statewide, and specific values for externalities have been adopted by the Massachusetts Department of Public Utilities, the California Energy Commission, the California PUC, the Nevada PSC, and the Bonneville Power Administration. All of the regulators used the RCC approach to valuing externalities; the BPA used damage estimates. The values selected by various jurisdictions are summarized in Exhibit PLC-2, which is in part an update to Appendix A to HL&P's Study 6.[5] The New Jersey Board of Regulatory Commissioners has adopted externality adders for electric and gas conservation program screening based on the monetized externalities estimated in *The Environmental Costs of Electricity*, but did not endorse values for individual pollutants.

Q: Are other states active in considering externalities in resource planning?

A: Yes. According to a survey performed by the National Association of Regulatory Utility Commissioners in 1990, 22 states reported that they were developing an externality valuation approach, incorporation is pending, or their approach is fully operational (NARUC, 1990).[6] Pace University reports similar participation by Public Utility Commissions (Ottinger, 1990).

V. HL&P'S EXTERNALITY ANALYSES

Q: What analyses of externality values does HL&P sponsor in this proceeding?

---

[5] Study #6 has some peculiar errors. As discussed below, the BPA NO_x values are incorrect. The CO_2 value attributed to me is attributed to the Pace study; I cannot find any reference to my recommending the use of a $90/T value for CO_2 in the Pace study or any other publication, nor do I recall having recommended this value.

[6] This tabulation includes states that all have preferential rate recovery for DSM programs, which would not fit my description of incorporating externalities.

A: HL&P sponsors "Study 6: An Analysis of External Costs (Externalities)" through the direct testimony of Mr. Griffey, comparison of certain resource options with and without externality values through the direct and supplemental testimony of Mr. Griffey, and a recommendation by Mr. Feith that a zero value be used for CO_2.

Q: What are the problems you have identified in HL&P's analysis of externalities?

A: I have identified six problems. First, HL&P has made no effort to deal with any externality other than air emissions. Other potentially important externalities for HL&P's system would include water use, the discharge of chemicals and heat to water bodies, and the generation of solid and liquid wastes. While these externalities may be more difficult to monetize, HL&P can quantify the effects, and develop at least rough estimates of the RCC for some of them.

Second, HL&P has monetized only four externalities, all air emissions: CO_2, NO_x, CO, and SO_2.[7] This was an odd group to select. Since CO emissions from most utility power plants are quite small, CO is not normally an important consideration in utility resource planning. NO_x and CO_2 are likely to be the most important externalities for HL&P, followed by SO_2, particulates, and heavy metals (not necessarily in that order). I will ignore the CO valuation, which is of no importance, as Mr. Griffey acknowledges (Griffey Direct, p. 39.).

Third, HL&P generally uses externality values (in $/T) that are too low.

Fourth, HL&P overstates the NO_x emissions avoided by the DuPont project, both from the HL&P system and the DuPont boilers.

---

[7]Study #6 does not show any SO_2 emissions though HL&P does appear to show a monetarized value for such emission in response to Destec RFI2-41.

but only to 2000

Fifth, HL&P has failed to use its externality values in a consistent analysis of alternatives to the DuPont project.

All of these points, other than the first two, are discussed in greater detail.

A. HL&P's Externality Values

Q: Does HL&P's Study #6 use reasonable externality values?

A: No. HL&P uses no local or Texas-specific data in selecting values. Study #6 uses three sets of externality values for SO_2, NO_x, and CO_2, ranging from minuscule to modest. The source of these values are the Nevada PSC, the New York PSC, and Bonneville Power Administration (BPA).[8] HL&P took the lowest value of each pollutant for its "low" case, the median value for its "median" case, and the highest of the three values for its "high" case.

The Nevada PSC values for SO_2 and NO_x are reasonable estimates of RCC values for Nevada, but are too low for H&LP. The population densities in and around Nevada are much lower than those in and around HL&P's service territory. Also, Nevada is in attainment for ozone, while Houston is a "severe" non-attainment area.[9] Both damages and control costs per ton are likely to be much higher for HL&P than for Nevada.

The BPA values are damage cost estimates for clean, low-population areas. Among other problems, the underlying damage study ignored ozone's health effects.

---

[8]The NO_x value used by HL&P appears to be an error. As reported in Bowers (1991), the correct NO_x values are $68.80/T in east of the Cascades and $884.20/T west of the Cascades. HL&P reports $67.65/T for both areas, and uses this value as its low NO_x value.

[9]Houston is also only marginally in compliance with Federal SO_2 levels; allowing for future growth may require stricter SO_2 controls in HL&P's service territory than in Nevada.

The NYPSC values are not the full marginal cost of required controls, but the average of high-cost and low-cost controls estimated by the NY State Energy Office (NYSEO). More recent NYSEO estimates of RCC are on the order of $9,400/T for NOx, and $1,300/T for SO_2.

Q: What sources should HL&P have used in valuing emissions on its system?

A: HL&P should have used the most relevant available data. Ideally, those data would be specific to the Houston CMSA. Where Houston data are not available, HL&P should look to areas facing similar environmental conditions and constraints. For example, HL&P might have more appropriately used the costs of controls currently required in Southern California, which may also be required over the next several years for Houston.[10] The most recent externality values estimated from cost of control by the California Energy Commission and Public Utility Commission are listed in Exhibit PLC-2.

A more relevant value for NO_x can be estimated from controls currently required in HL&P's own service territory. The Texas Air Control Board has required selective catalytic reduction (SCR) to achieve 9 ppm NO_x on gas turbine cogenerators of more than 10 MW, unless they can reduce emissions to less than 15 ppm without SCR.[11] TACB estimated that the cost of SCR for "a recent" cogeneration application, reducing emissions from 25 ppm to 9 ppm, was $6,627/T NO_x (Hamilton, 1991). The cost per ton would be higher for small

---

[10]The Los Angeles air basin is the only one in the country in a worse ozone category than Houston. I understand that Jesse Frederick testifies that the TACB Rules will likely follow those of the South Coast Air Quality Management District for the Los Angeles Basin.

[11]The waiver of SCR on these low-NO_x units is based on both the cost of the SCR and on the inevitable "slip" of ammonia from the SCR system. TACB measures NO_x dry at 15% O_2.

units.

HL&P expects that "as a result of the Clean Air Act Amendments of 1990 [TACB] will require that combined cycle power plants requesting air permits after November 15, 1992 use [SCR] for NO_x control" (Griffey Supplemental Testimony, p. 2). Control requirements are generally similar for all large high-load-factor combustion turbines, whether used in cogeneration or combined cycle applications. The addition of SCR would reduce NO_x emissions from 15 ppm to 5 ppm (Id., p. 5). HL&P equates the 15 ppm emission level to 0.06 lb/MMBTU, and 5 ppm to 0.02 lb/MMBTU. Assuming that the cost per kW-year is the same for the decrement from 15 to 5 ppm as for 25 to 9 ppm, the smaller reduction in emissions would increase the control cost to $10,600/T.[12]

This value is confirmed by recent estimates for local projects. For the DuPont project itself, HL&P estimates an incremental SCR cost of reducing emissions from 15 to 5 ppm of $9,900/T (1991$, from DR DEI2-176, p. 59). Exhibit PLC-3 computes the costs of SCR for the 15 to 5 ppm decrement, based on the NO_x control costs reported for the Hill Petroleum cogenerator, consisting of two 34.5 MW turbines. The estimated cost of NO_x control, adjusted to a 10 ppm decrement, is about $18,800/T. This estimate is considerably higher than those derived above, perhaps due to the small size of the Hill Petroleum plant. The cost of control would be even higher for a 10 MW unit.

Had HL&P used local control costs to determine the costs imposed by NO_x

[12]This estimate may be on the low side, even for the TACB example unit, since the lower concentrations may require more catalyst area to achieve the same percentage reduction. For small units, the cost would be even higher.

emission, it would have estimated an RCC externality value for NO_x of about $15,000/T.

The marginal cost of control for NO_x in the Houston area may well be higher than the marginal cost required for new utility plants, and may include retrofits to existing utility plants, controls on industrial boilers, transportation controls, or other measures. Under the CAAA, the Houston area has been classified as a Severe Ozone Non-Attainment Area, with an ozone design value of 0.22 ppm.[13] Given this classification, Houston must comply with a number of requirements, including:[14]

- attaining the national ambient air quality standard (NAAQS) for ozone of 0.12 ppm by 2007;
- reducing vehicle miles traveled, through government action and though mandatory employer vehicle occupancy reduction plans;
- installing gasoline vapor recovery (stage II);
- submitting to EPA a clean-fuel vehicle program for fleet vehicles;
- enhancing inspection and monitoring programs for motor vehicles;
- applying new source review requirements to new and modified major VOC and NOx sources (i.e., those with the potential to emit over 25 tons/year), including
    - offsets of 120% of emissions if Best Available Control Technology (BACT) is required for existing sources; or else offsets of 130%;
    - 130% internal offsets for some modifications of existing facilities;
- requiring Reasonably Available Control Technology (RACT) on all existing major stationary VOC and NO_x sources;

---

[13] The design value is the fourth highest reading of ozone concentration, taken over a 24-hour period.

[14] See National Research Council (1991), p.70; Sidley & Austin, (1991); US EPA (1990).

- reducing VOC emissions by 15% from 1990 levels by 1996, or the equivalent in combined VOC and NO_x reductions;[15]

- reducing VOC emissions (or the equivalent in NO_x and VOC) by another 3% annually until attainment; and

- demonstrating that the 3% reductions have been achieved on an average basis every three years.

The NO_x requirements can be waived by EPA if it determines that NO_x reductions would not be helpful in reducing ozone. Given the high 12.9:1 ratio of VOCs to NOx estimated for Houston (National Research Council, 1991), NO_x reductions are likely to be particularly valuable and essential in controlling ozone levels for the Houston area.[16]

Q: Is HL&P's treatment of CO_2 reasonable?

A: No. HL&P's preferred value of $0/T is inconsistent with the bulk of the evidence, with the opinions of the majority of climatologists, and with the determination of every state that has monetized externalities. The potential effects of global warming are discussed in Ottinger, et al. (1990), US EPA (1989), and IPCC (1990), among others.

I proposed a CO_2 value of $22/T for the Massachusetts DPU; it was subsequently adopted by the Nevada PSC, as well. It is roughly consistent with the value of $10/T used by the National Academy of Sciences (1991) as a definition of "low-cost" CO_2 reduction measures. In utility terms, the NAS value

---

[15]These reductions are in addition to those achieved through mandated controls, such as on motor vehicle tailpipe emissions and fuel volatility, and through compliance with regulations promulgated before 1990.

[16]For comparison, the VOC:NO_x ratio is 7.8 in Los Angeles, and in the 7.6-9.6 range in various parts of NESCAUM.

would be about \$17/T.[17]

In order to keep the rate of climate change close to that experienced in the geological record, current research indicates that it may be necessary for the developed countries to reduce CO_2 emissions by roughly 20% from 1990 levels by 2005 or 2010, and by 80% by 2030. (Krause, Bach and Koomey, 1989) With 2% base case growth in carbon emissions, this would require reductions of 45% from the base case by 2010; even stabilizing emissions at 1990 levels would require an 18% reduction from the base case by 2000 and a 33% reduction by 2010. As shown in Exhibit PLC-4, the estimates of the marginal cost of control to achieve significant reductions in emissions are estimated to range from \$23/T to \$261/T, depending on the geographical area, time period, and sectors covered, as well as the assumptions and methodology used. Thus \$22/T is on the low end of the scale.

Q: **If the Commission determined that the effects of increased atmospheric CO_2 were as likely to be beneficial as damaging, should the Commission use a zero value for CO_2?**

A: No. The uncertainty in the effects argues for avoidance of global warming. Increasing CO_2 levels would amount to a massive experiment with the entire world, with effects that may be disastrous and irreversible; correspondingly large benefits are unlikely. The island nations, which are at great risk from global warming, voiced such concerns at the recent Rio conference.

---

[17]The NAS value is for costs computed at a 6% real discount rate without taxes, which would imply a 7% carrying charge for long-lived measures; typical real carrying charges for investor-owned utilities are on the order of 12%.

B. HL&P Emissions Estimates

Q: Has HL&P properly modelled the environmental benefits of the DuPont project?

A: No. HL&P overstates the NO_x benefits by overstating the future emission rates of its marginal power plants and of the existing DuPont boilers.

Q: How did HL&P overstate the future emission rates for its marginal power plants?

A: HL&P assumes that NO_x emission rates remain at current levels throughout the period 1995-2024. The bulk of the HL&P NO_x reductions attributed to the operation of the DuPont project are from the existing gas-fired steam plants, which HL&P reports as having an average emission rate of 0.55 lb/MMBTU.[18] This emission rate is unrealistic beyond the middle of this decade, given two provisions of the CAAA, and HL&P's reliance on that rate results in HL&P seriously overstating its NO_x reductions.

Title IV of the CAAA requires that each power plant covered by the SO_2 allowance system install low-NO_x burners by the time it is covered.[19] For HL&P, all fossil-fueled units are covered in the year 2000. As discussed above, NO_x emissions in the Houston area will also have to be reduced to comply with Title I of the CAAA. Thus, the HL&P utility system will get considerably cleaner at the margin, with or without the DuPont plant. Additionally, existing units will have to install RACT. I understand that Jesse Frederick will testify that RACT will likely limit NO_x emissions to 25 PPM in exhaust of GE gas

---

[18]Much smaller NO_x savings are attributed to reduced operation of Parish 5-8, at 0.31-0.41 lb/MMBTU, and Limestone, at 0.5 lb/MMBTU.

[19]EPA may define "low-NO_x burners" to include other combustion modifications.

turbines larger than 30 MW.

Q: How much would you expect the emissions of HL&P's existing plants to decline as a result of CAAA implementation?

A: TACB does not appear to have released any information on the State Implementation Plan (SIP) it is preparing for the Houston CMSA. I do have data on the controls to be required by the eight states of NESCAUM (Northeast States for Coordinated Air Use Management), with generally lower ozone levels than Houston. NESCAUM has reached preliminary agreement to require combustion reductions in gas-fired steam units to 0.20 lb/MMBTU by May 15, 1995.[20] This is slightly better than the 0.25 lb/MMBTU that HL&P projects for its refurbished gas steam plants.[21] By May 15, 1999, NESCAUM is preparing to add post-combustion controls (either SCR or selective non-catalytic reduction, SNCR) to bring gas and oil plant emissions down to 0.10 lb/MMBTU.

Exhibits PLC-5, 6, and 7 revise HL&P's analyses of system NOx emission reductions. Since HL&P provided two emission analyses (one dated 5/13/92 in Response DEI2-41, p. 14, and another dated 7/16/92 in Mr. Griffey's workpapers) and has not explained why the runs are different, I have corrected both analyses. As shown in Exhibit PLC-5, the May analysis, which assumed the Webster refurbishing in 1995, but no other additions, and no replacement for the DuPont

#/MMBTU + changes

unrealistic constant-load assumption

---

[20] I understand that Jesse Frederick will testify that 0.20 lb/MMBTU is also the emissions factor likely to be adopted by Regulation 7, the Texas rule implementing the RACT provisions of the CAAA.

[21] The NESCAUM emission limits are maxima for one-hour periods, implying that the annual average emission rates would be somewhat lower.

plant, estimated that systems NOx emissions would decline by 2,845 tons.[22] With the NESCAUM Phase 1 combustion controls on gas steam units, the reduction would be only 954 tons. With the Phase 2 controls, the reduction would fall to 264 tons, an order of magnitude less than HL&P's estimate.

Exhibit PLC-6 shows that the same pattern applies for the July analysis, with similar assumptions but without the Webster refurbishment. With realistic late-90s emission rates for the Houston area, HL&P system NO_x emissions rise only 762 T with combustion controls, or 147 T with selective reduction, not the 2,797 T produced by HL&P's emission assumptions.

Q: **In Exhibits PLC-5 and 6, you also reduce the emission rate for the DuPont boilers. Why is this?**

A: Large industrial boilers will also be regulated under Title I of the CAAA. The DuPont boiler has an NO_x emission rate of 0.2232 lb/MMBTU; EPA's AP-42 emissions compilation cites 0.14 lb/MMBTU as typical for industrial boilers. These boilers will either be replaced or retrofitted with combustion controls and/or selective reduction. Again, TACB's plans for industrial boiler retrofits do not appear to be publicly available. However, South Coast Air Quality Management District (SCAQMD) has required large boilers to achieve 0.05 lb/MMBTU since 1988, based on the conclusion that the standard can be met for about $10,000/T using low-NOx burners, flue-gas recirculation (FGR), and perhaps SNCR (SCAQMD 1989). The Coen Company claims that its Micro-NOx burners can reduce emissions to this range with just FGR. SCAQMD proposed

---

[22]Most of the data in HL&P's analysis labeled "tons" was really in thousands of pounds.

reducing the emission limit for large boilers another 25% (to 0.038 lb/MMBTU) using SCR but this proposal has been superceded by the NO_x trading proposal. I used the current SCAQMD rules as my estimate of Phase I emissions from the DuPont boilers; and the proposed SCAQMD level for Phase II.[23]

Q: How does correcting the DuPont boiler emission factor affect the total change in emissions due to the HL&P/DuPont Project?

A: Under HL&P's assumptions, the total NO_x reduction from replacing the DuPont boilers and some marginal HL&P generation with the DuPont Project is in the range of 3724 to 3772 tons. With combustion controls on gas plants, the savings fall to between 970 and 1161 tons; with selective reduction, the NO_x benefit of the DuPont Project is in the range of 303 to 420 tons. Thus, the NO_x benefits of the DuPont Project are overstated by a factor of at least three times, and probably more like ten times.

Of course, if the DuPont Project does not entirely eliminate the operation of the existing boilers, the benefits will be even smaller.

Q: Is the comparison of the HL&P system with the DuPont Project to the same system without the Project appropriate for the entire analysis period?

A: No. The DuPont Project is expected to displace only the existing system through 1999. Starting in the year 2000, the DuPont Project backs out a gas combined-cycle unit (Griffey Direct, Figure CSG-5; Griffey Supplemental, Figure CSG-S2; Naeve Direct, Figures SWN-2 and SWN-10). Since the NO_x emissions (per MMBTU and per kWh) of the combined-cycle plant will be lower than those of

---

[23]These Phases are not the same as in Title IV; they are the short-term and 1999 targets set by NESCAUM.

the existing marginal gas steam units and of the DuPont Project, the NO_x benefits from the Project will be lower once it is backing out the combined-cycle unit.[24]

I evaluate these benefits in Exhibit PLC-7. I use HL&P's May analysis (DR DEI2-41, p. 4) of MMBTU usage for each unit in 1995, to avoid confusion between the emissions of the DuPont plant and the combined cycle plants, which HL&P reports on a single line. HL&P computes fuel use for each category of plants for one plan with the DuPont plant and another with a combined cycle unit. Since this part of the HL&P analysis did not include the DuPont boilers, or the fuel use of the DuPont Project to serve the DuPont steam load, I used the DuPont boiler and Project energy use from page 14 of DR DEI2-41.

Q: What is the result of comparing emissions with the DuPont unit to those with the combined cycle plant, for realistic emission rates?

A: As shown in Exhibit PLC-7, the NO_x benefits would be 1153 T under HL&P's assumptions, falling to 231 T for combustion controls. With selective reduction on existing units, total emissions would be *higher* with the DuPont Project than with the combined cycle plant.

Q: Is your correction of HL&P's emission analysis conservative in any way?

A: Yes. I accepted all of HL&P's input data, except for future emission rates of existing sources. Most importantly, my computations use the emissions of the DuPont Project that HL&P filed with the PUC, rather than the apparently

[24]The same is true if the Du Pont Project is used to back down the existing cogenerators, avoiding only a relatively low lb/MMBTU emission rate at a very low heat rate.

higher values filed with the TACB.[25]

While the DuPont Project emissions have probably been understated, the emission rates for existing units with new pollution controls are probably overstated. I used maximum hourly emission rates for controlled units as if they were annual averages; the annual average emission rates should be lower. Lower emissions from existing units would further reduce the environmental benefits of the Project.

Another important conservatism is my omission of the effect of the DuPont Project on existing cogeneration contracts. Mr. Naeve (Direct, Figures SWN-2 and SWN-10) suggests that HL&P would use the DuPont unit to reduce purchases from existing cogenerators, including Occidental, Dow, and AES. Those cogenerators would then be used to serve the electric loads of their steam hosts, in some cases replacing interruptible purchases from HL&P. This change could have two detrimental effects. First, the cogenerators may be dispatched at lower and less efficient levels to serve internal loads in low-load periods. In this situation, the DuPont Project will have avoided only the low incremental emissions of the cogenerators, which will certainly be lower than the system incremental emissions and may be lower than the DuPont emissions. Thus, some very efficient and clean energy production may be lost to the HL&P system and Texas. Second, the loss of these large short-lead-time interruptibles would tend to increase HL&P's requirement for spinning reserves. If HL&P must keep

---

[25] I understand that Jesse Frederick will testify that HL&P's Permit Application to the TACB estimates annual NO_x emissions from the Du Pont Project of 888 T/yr, rather than the 482 T/yr HL&P assumes in this docket. If HL&P's estimate before the TACB is accurate, the Project would decisively increase total NO_x emissions.

steam units warm, or running at low load levels, efficiency will be low and emissions will be high. HL&P does not appear to have considered the environmental benefits of maintaining its relationship with the cogenerators, including the interruptible load; this is a major failure of the analysis.

Since the NO_x benefits of the DuPont Project would be somewhere between slightly negative to barely positive, depending on the actual future emissions rates of other plants, these conservatisms are particularly important. The NO_x benefits could become significantly negative with even small increases in project emission rates, decreases in annual emission rates from other units, or operational inefficiencies due to HL&P's termination of cogeneration purchases.

Q. What is your conclusion?

A. My opinion is, given the very limited data that HL&P has generated, that the DuPont Project will certainly not produce anything like the benefits represented in Study #6 and it is more likely than not that when a "reasonable" study of the project is done, the DuPont Project will have a more negative impact on the environment than the construction of a combined cycle plant, the extension of the cogeneration contracts, and other alternatives in the time frame suggested here.

VI. THE HL&P/DUPONT PROJECT IN A LEAST-COST CONTEXT

Q: Has HL&P properly evaluated the DuPont Project in a least-cost planning framework?

A: No. In addition to its failure to produce reasonable externality estimates, HL&P

has failed to use least-cost planning principles, in at least three ways.[26]

First, HL&P has not demonstrated that best use of the DuPont site is the construction of a 158 MW simple-cycle gas turbine cogenerator. HL&P refers to the DuPont project as a "lost opportunity," but it is the site and the steam host that present a real lost opportunity. If HL&P ties up that site with a 158 MW simple-cycle cogenerator, when a larger and/or more efficient cogenerator (especially a combined-cycle unit) would have been cost-effective, reducing direct costs and environmental externalities, the option of upgrading the site is probably lost for decades.

Second, while it would be laudable for HL&P to invest in resources that reduce environmental externalities, it is unlikely that the DuPont project is the best place for HL&P to be investing its environmental clean-up budget.[27] As shown in Exhibit PLC-8, the net cost of the DuPont Project is equivalent to $1700/T of NOx saved, for current emission rates, and $5500/T of NOx once the gas plants have been equipped with combustion modifications, much of which is likely to occur by 1995 or shortly thereafter. HL&P could clean up its system faster by accelerating the retrofit of combustion modifications on coal and gas plants, installing SCR, investing in energy efficiency programs, and the like, rather than spending the funds on the DuPont project. Any reasonable approach to incorporating externalities in least-cost planning would include this broader

---

[26] I have not reviewed comments on HL&P's system modelling, in McModel or Proscreen; any errors in the modelling inputs or assumptions are in addition to my comments on its planning process.

[27] Indeed, as shown above, it is not clear at all that the DuPont project would result in a net reduction in NO_x emissions.

perspective.

Third, as shown in Mr. Griffey's Figures CSG-4, CSG-8, CSG-S1 and CSG-S5, HL&P improperly uses $/kW net benefits to sort resource options. Cost-effective high-load-factor options will tend to have higher $/kW benefits than low-load-factor options with the same net benefits, since the high-load-factor option has fewer kW per kWh. A 100 MW option with net benefits of $200 million would have benefits of $2,000/kW, while a 200 MW resource that saved $300 million would have only $1,500/kW benefits. Depending on the load factors, the two options could provide the same amount of energy, say 800 GWH/yr. The net benefit of the 100 MW option, stated in energy terms, is $0.25/GWH-yr, while that of the 200 MW option is $0.375/GWH-yr. The energy ranking is the opposite of the capacity ranking. The 200 MW option might well be preferable to the 100 MW option; the $/kW ranking is not particularly informative. HL&P distorts the externality analysis by expressing the results in terms of $/kW.

If the Commission intends to apply least-cost planning principles to CCN applications, the deficiencies in the planning process require denial of the certificate application for the HL&P DuPont Project.

Q: Does this conclude your testimony?

A: Yes.

BIBLIOGRAPHY

Chernick, PL, and Birner, SA, "The Indispensability of Externality Valuation in Least-cost Planning," in *Incorporation of Environmental Externalities in Resource Acquisition Decisions in the United States and Europe*, Proceedings of the Second International Conference on External Costs of Electric Power, in press, 1992

Chernick, PL, and Caverhill, EJ, "Externalities," in *From Here to Efficiency*, report to the Pennsylvania Energy Office, 1992

Hamilton, R, "BACT Recommendation for Gas Turbine Cogeneration (GTC) projects in Texas," June 6, 1991

Intergovernmental Panel on Climate Change, *Climate Change: The IPCC Scientific Assessment*, 1990

Krause, F, Bach and Koomey, J, *Energy Policy in the Greenhouse: From Warming Fate to Warming Limit*, 1989

National Academy of Sciences, *Policy Implications of Greenhouse Warming, Report of the Mitigation Panel*, 1991

National Association of Regulatory Utility Commissioners, 1990 xx

National Research Council, *Rethinking the Ozone Problem in Urban and Regional Air Pollution*, National Academy Press, 1991.

Neme C, *Electric Utilities and Long-Range Transport of Mercury and Other Toxic Air Pollutants*, Center for Clean Air Policy, November, 1991.

New York State Energy Office, Department of Public Service, and Department of Environmental Conservation; *Draft New York State Energy Plan, Volume VI: Electricity Issues*, May 1989.

New York State Energy Office, Department of Public Service, and Department of Environmental Conservation; *Draft New York State Energy Plan, 1991 Biennial Update, Volume III: Issue Reports*; July 1991.

Ottinger, RL, "Incorporation of Environmental Externalities in the United States of America," in Hohmeyer, O, and Ottinger, RL (eds.) *External Environmental Costs of Electric Power: Analysis and Internalization*, Springer-Verlag, 1990

Ottinger, RL, et al., *Environmental Costs of Electricity*, Ocean Publications; 1990

Sidley & Austin, *Overview of Environmental Health and Safety Obligations and Liabilities (Environmental Resource)*, April 1991.

South Coast Air Quality Management District, *Final Air Quality Management Plan, 1989 Revisions: Appendix IV-A*, March 1989

US EPA, *The Potential Effects of Global Warming Climate Change on the United States*; Report to Congress by the Office of Policy, Planning and Evaluation, Office of Research and Development; December, 1989

US EPA, *Clean Air Act Amendments of 1990: Detailed Summary of Titles*, November 30, 1990

EXHIBIT LIST OF PAUL L. CHERNICK

Attachment 1

Resume of

Paul L. Chernick

EXHIBIT PLC-1

PAUL L. CHERNICK

Resource Insight, Inc.
18 Tremont Street, Suite 1000
Boston, Massachusetts 02108

PROFESSIONAL EXPERIENCE

President, Resource Insight, Inc.
August 1986 - present

Consulting and testimony in utility and insurance economics. Reviewing utility supply planning processes and outcomes: assessing prudence of prior power planning investment decisions, identifying excess generating capacity, analyzing effects of power pool pricing rules on equity and utility incentives. Reviewing electric utility rate design. Estimating magnitude and cost of future load growth. Designing and evaluating electric, natural gas, and water utility conservation programs, including hook-up charges and conservation cost recovery mechanisms.

Determining avoided costs due to cogenerators. Evaluating cogeneration rate risk. Negotiating cogeneration contracts. Reviewing management and pricing of district heating system.

Determining fair profit margins for automobile and workers' compensation insurance lines, incorporating reward for risk, return on investments, and tax effects. Determining profitability of transportation services.

Advising regulatory commissions in least-cost planning, rate design, and cost allocation.

Research Associate, Analysis and Inference, Inc.
May 1981 - August 1986 (Consultant, 1980-1981)

Research, consulting and testimony 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.

Utility Rate Analyst, Massachusetts Attorney General
December 1977 - May 1981

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.

PROFESSIONAL AFFILIATIONS

Senior Associate, Cambridge Energy Research Associates, Cambridge, Massachusetts.
Associate, Rocky Mountain Institute Competitek Service, Old Snowmass, Colorado.
Member, International Association for Energy Economics, and past Vice-President, New England Chapter.
Member, Association of Energy Engineers, Lilburn, Georgia.

EDUCATION

S.M., Technology and Policy Program, Massachusetts Institute of Technology, February, 1978.

S.B., Civil Engineering Department, Massachusetts Institute of Technology, June, 1974.

HONORARY SOCIETIES

Chi Epsilon (Civil Engineering)
Tau Beta Pi (Engineering)
Sigma Xi (Research)

OTHER HONORS

Institute Award, Institute of Public Utilities, 1981.

PUBLICATIONS

Chernick, P. et al., "Benefit-Cost Ratios Ignore Interclass Equity," DSM Quarterly, Spring 1992.

Chernick, P. and Birner, S., "ESCOs or Utility Programs: Which Are More Likely to Succeed?," The Electricity Journal, Vol. 5, No. 2, March 1992.

Chernick, P. and Schoenberg, J., "Determining the Marginal Value of Greenhouse Gas Emissions," Energy Developments in the 1990s: Challenges Facing Global/Pacific Markets, Vol. II, July 1991.

Chernick, P. and Caverhill, E., "Monetizing Environmental Externalities for Inclusion in Demand-Side Management Programs," in Proceedings from the Demand-Side Management and the Global Environment Conference, April 1991.

Caverhill, E. and Chernick, P., "Accounting for Externalities," Public Utilities Fortnightly, Vol. 127, No.5, March 1, 1991.

Chernick, P. and Caverhill, E., "Methods of Valuing Environmental Externalities," The Electricity Journal, Vol. 4, No. 2, March 1991.

Chernick, P. and Caverhill, E., "The Valuation of Environmental Externalities in Energy Conservation Planning," Energy Efficiency and the Environment: Forging the Link. American Council for an Energy-Efficient Economy; Washington: 1991.

Chernick, P. and Caverhill, E., "The Valuation of Environmental Externalities in Utility Regulation," External Environmental Costs of Electric Power: Analysis and Internalization. Springer-Verlag; Berlin: 1991.

Chernick, P., Espenhorst, E., and Goodman, I., "Analysis of Residential Fuel Switching as an Electric Conservation Option," Gas Energy Review, December 1990.

Chernick, P., "Externalities and Your Electric Bill," The Electricity Journal, October 1990, p. 64.

Chernick, P. and Caverhill, E., "Monetizing Externalities in Utility Regulations: The Role of Control Costs," in Proceedings from the NARUC National Conference on Environmental Externalities, October 1990.

Chernick, P. and Caverhill, E., "Monetizing Environmental Externalities in Utility Planning," in Proceedings from the NARUC Biennial Regulatory Information Conference, September 1990.

Chernick, P., Espenhorst, E., and Goodman, I., "Analysis of Residential Fuel Switching as an Electric Conservation Option," in Proceedings from the NARUC Biennial Regulatory Information Conference, September 1990.

Chernick, P. and Plunkett, J., "A Utility Planner's Checklist for Least-Cost Efficiency Investment," in Proceedings from the NARUC Biennial Regulatory Information Conference, September 1990.

Ottinger, R., et al., Environmental Costs of Electricity. Oceana; Dobbs Ferry, New York: September 1990.

Plunkett, J., Chernick, P., and Wallach, J., "Demand-Side Bidding: A Viable Least-Cost Resource Strategy," in Proceedings from the NARUC Biennial Regulatory Information Conference, September 1990.

Chernick, P. and Caverhill, E., "Incorporating Environmental Externalities in Evaluation of District Heating Options," in Proceedings from the International District Heating and Cooling Association 81st Annual Conference, June 1990.

Chernick, P. and Plunkett, J., "A Utility Planner's Checklist for Least-Cost Efficiency Investment," in Proceedings from the Canadian Electrical Association Demand-Side Management Conference, June 1990.

Chernick, P. and Caverhill, E., "Incorporating Environmental Externalities in Utility Planning," Canadian Electrical Association Demand Side Management Conference, May 1990.

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

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

Plunkett, J. and Chernick, P., "The Role of Revenue Losses in Evaluating Demand-Side Resources: An Economic Re-Appraisal," in Summer Study on Energy Efficiency in Buildings, 1988, American Council for an Energy Efficient Economy, 1988.

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

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

Chernick, P., "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.

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

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

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

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

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

Meyer, M., Chernick, P., and Fairley, W., "Insurance Market Assessment of Technological Risks," in Risk Analysis in the Private Sector, pp. 401-416, Plenum Press, New York, 1985.

Chernick, P., "Revenue Stability Target Ratemaking," Public Utilities Fortnightly, February 17, 1983, pp. 35-39.

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

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

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

PRESENTATIONS

American Planning Association 1992 National Planning Conference; May 10, 1992; "Using the Costs of Required Controls to Incorporate the Costs of Environmental Externalities in Non-Environmental Decision-Making."

DSM Advocacy Workshop; April 15, 1992; Session Leader for "Cost Recovery and Decoupling" and "The Clean Air Act and Externalities in Utility Resource Planning" panels.

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

Demand-Side Management and the Global Environment Conference; Washington, D.C., April 22, 1991; "Monetizing Environmental Externalities for Inclusion in Demand-Side Management Programs."

Conservation Law Foundation Utility Energy Efficiency Advocacy Workshop; Boston, February 28, 1991; "Least Cost Planning and Gas Utilities."

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

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

National Association of Regulatory Utility Commissioners' National Conference on Environmental Externalities; Jackson Hole, Wyoming, October 1, 1990; "Monetizing Externalities in Utility Regulations: The Role of Control Costs."

New England Gas Association Gas Utility Managers' Conference; Woodstock, Vermont, September 10, 1990; "Increasing Market Share Through Energy Efficiency."

Lawrence Berkeley Laboratory Training Program for Regulatory Staff; Berkeley, California, February 2, 1990; "Quantifying and Valuing Environmental Externalities."

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

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

New England Conference of Public Utilities Commissioners, Environmental Externalities Workshop; Portsmouth, N.H., January 22-23, 1989; "Assessment and Valuation of External Environmental Damages."

New England Utility Rate Forum; Plymouth, Massachusetts, October 11, 1985; "Lessons from Massachusetts on Long Term Rates for QFs".

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

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

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

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; "Insurance Market Assessment of Technological Risks".

REPORTS (excluding reports incorporated in testimony)

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

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

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

"Comments on the 1991-1992 Annual and Long Range Demand Side Management Plans of the Major Electric Utilities," (with Plunkett, J., et al.), September 1990.

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

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

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

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

"Conservation Potential in the State of Minnesota," (with I. 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.

ADVISORY ASSIGNMENTS TO REGULATORY COMMISSIONS

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

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

EXPERT TESTIMONY

In each entry, the following information is presented in order: jurisdiction and docket number; title of case; client; date testimony filed; and subject matter covered. Abbreviations of jurisdictions include: MDPU (Massachusetts Department of Public Utilities); MEFSC (Massachusetts Energy Facilities Siting Council); PSC (Public Service Commission); and PUC (Public Utilities Commission).

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 S.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. Atomic Safety and Licensing Board, Nuclear Regulatory Commission 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 cancelled 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, cogeneration, 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 Public Service Commission 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 streetlighting 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 Public Service Commission 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 Public Service Commission 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 Public Service Commission 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 cashflows, 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 Public Service Commission 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. Massachusetts Department of Public Utilities 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. Massachusetts Department of Public Utilities 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. Massachusetts Department of Public Utilities 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 Public Utility Commission 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 Public Service Board Docket No. 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 Public Service Board Docket No. 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 Public Service Board Docket 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.

I.89-07-004 Biennial Resource Plan Update

82. California Public Utilities Commission; ~~Incorporation of Environmental Externalities in Utility Planning and Pricing~~; Coalition of Energy Efficient and Renewable Technologies; February 21, 1990. Joint testimony w/ [illegible]

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 Public Service Commission Case No. 8278; ~~Adequacy of~~ Baltimore Gas & Electric's Integrated ~~Resource~~ Plan; Maryland Office of People's Counsel; September 18, 1990. rate case

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 Dockets 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 Docket No. 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. Commonwealth of Virginia State Corporation Commission Case No. 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. Massachusetts DPU Docket No. 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. Commonwealth of Massachusetts; 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 Docket No. 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.

+ Vt externalities

93. South Carolina Public Service Commission Docket No. 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.

perryman C.C.1)

94. Maryland Public Service Commission Case No. 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. Massachusetts DPU Docket No. 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 chlorofluorocarbrons, air toxics, thermal pollution, and oil import premium. Review of state regulatory actions regarding externalities.

97. Florida PSC Docket No. 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 Docket No. 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 Dockets 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 Docket No. 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. Massachusetts DPU Docket No. 92-92; Adequacy of Boston Edison's Streetlighting Options; Town of Lexington; June 22, 1992.

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

102. South Carolina PSC Docket No. 92-208-E; Petition of the State of Carolina In Re Duke Power; South Caroline Department of Consumer Affairs; Augist 4, 1992

    Duke Power's DSM screening, estimation of avoided cost, and program design.

Table 1: Summary of Externality Values (1989$ per ton unless otherwise noted)

22-Sep-92

Externality	Calif. PUC SCE&SDG [1]	Calif. PUC PG&E [2]	Calif. ER-90 in-state [3]	Calif. ER-90 out-state [4]	Mass. DPU [5]	Nevada PSC [6]	New York PSC [7]	New York SEO [8]	BPA West [9]	BPA East [10]	Pace Univ. [11]
SO2	20,253	4,483	18,104	1,513	1,500	1,560	832	858	1,500	1500	4,060
NOx	27,114	1,956	18,262	4,084	6,500	6,800	1,832	4,204	884	69	1,640
VOC/ROG	19,367	3,652	5,196	454	5,300	1,180	NE	NE	NE	NE	NE
PM10/TSP	5,866	2,634	12,279	1,210	4,000	4,180	333	NE	1,540	167	2,380
CO	NE	NE	NE	NE	870	920	NE	NE	NE	NE	NE
CO2	7.6	7.6	7.6	7.6	22	22	1	74	NE	NE	13.6
CH4	NE	NE	NE	NE	220	220	NE	NE	NE	NE	NE
N2O	NE	NE	NE	NE	3,960	4,140	NE	NE	NE	NE	NE
water use (c/kWh)	NE	NE	NE	NE	NE	site-spec.	0.1	NE	NE	NE	NE
land use (c/kWh)	NE	NE	NE	NE	NE	site-spec.	0.4	NE	0-0.2	0-0.2	NE

Notes:

[1][2][3][4]: California Energy Commission, "In-state Criteria Pollutant Emission Reduction Values," Testimony of Buell, Diamond, Magalletti and Tanton, Table 2, November 19, 1991.

[5]: Massachusetts DPU Decision in Docket 89-239. August 31, 1990.

[6]: Nevada PSC Docket No. 89-752. January 22, 1991. Values expressed in 1990$. NOx and VOC values are for ozone non-attainment areas. NOx value for non-attainment area would be higher, and VOC value would be $5,500/ton.

[7]: 1991 Biennial Update of the New York State Draft Energy Plan, Issues Report, July 1991. Values expressed in $1990.

[8]: NYPSC, "Consideration of Environmental Externalities in New York State Utilities Bidding Programs," 1989. Values are: 0.25 c/kWh for SO2, 0.55 c/kWh for NOx, 0.1 c/kWh for CO2, 0.005 for TSP, 0.1 c/kWh for water discharge, and 0.4 c/kWh for land use impacts for a total of 1.405 c/kWh total for a NSPS coal plant. Values are translated to $/ton by Sury Putta, "Weighing Externalities in New York State," The Electricity Journal, July 1990.

[9][10]: 1990$. Bonneville Power Administration, "Application of Environmental Cost Adjustments During Resource Cost Effectiveness Determinations," May 15, 1991. "Land and other" values vary from 0 for DSM to 0.2 c/kWh for coal and new hydro. SO2 value is zero if offsets are purchased.

[11]: Ottinger et al., "Environmental Costs of Electricity," Pace University, 1990.

EXHIBIT PLC-2

Table 2: Computation of SCR on Low-NOx Cogenerator
Based on Data from Hill Petroleum Cogenerator

	Steam	Steam + SCR	Difference	Adjust to Low-NOx
NOx ppm	39	12	27	10
Annual cost ($1000)	$70	$3,472	$3,402	$3,402
NOx reduced (T/yr)	850.8	1,358.6	507.8	188.1
$/T (1989$)	$82	$2,556	$6,699	$18,089
$/T (1990$)	$86	$2,658	$6,967	$18,812

Notes: Two units, 34.5 MW each.
Data from "Hill Petroleum Company: Control Technology Evaluation, Cogeneration Plant," ESNR Consulting and Engineering, February 1989.

Table 3: Estimates of the Cost of CO2 Emissions Reductions

Source and Measure [a]	Cost of reduction 1990$/T CO2 [b]	Percent reduction from base [c]	
[1] Danish Ministry of Energy			
Change from an economic growth scenario to			
an environmental growth scenario			
in 2000	$68	12%	
in 2015	$131	10%	
in 2030	$182	12%	
[2] New York State Energy Office	$65	28%	Stabilize at 1988 level
Statewide, all sources, for 2008	$120	31%	5% reduction from 1988
[3] Nordhaus mix	$23	17%	
(sequestration, emission reduction)	$28	21%	
	$48	25%	
	$78	34%	
	$119	42%	
[4] Spectrum Economics	$49	25%	
Utility sector mix (tree planting,	$88	29%	
conservation, fuel switching,	$172	33%	
renewables, etc.); reduction by 2008.	$261	37%	

NOTES:

[b]: 4% annual inflation assumed

[1]: Danish Ministry of Energy, "Energy 2000," April 1990. The environmental scenario emphasizes reducting energy consumption. The economic scenario assumes all cost-effective reduction options have been carried out by 2000, resulting in relatively low base emissions. Costs for the individual measures are average measure costs. Exchange rate: 6.585 krone/$.

[2]: 1991 New York State Energy Plan, "Analysis of Carbon Reduction in New York State" Marginal cost from Fig. IV.4, reduced by SO2 and NOX benefits, Fig. IV.7.

[3]: Nordhaus, W.D., "A Survey of Estimates of the Cost of Reduction of Greenhouse Gas Emissions," 1990.

[4]: Spectrum Economics, "Economic Impacts of the Greenhouse Gas Reduction Plan," 1990.

Table 4: Correction of HL&P 5/92 Emissions Analysis

	HL&P Emit #/MMBTU	W/O	With	Delta	Emits w/ CAAA Ph 1 #/MMBTU	Delta	Emits w/ CAAA Ph 2 #/MMBTU	Delta
L1	0.510	14652	14645	7	0.510	7	0.200	3
L2	0.480	12097	11997	100	0.480	100	0.200	42
WP5	0.322	7361	7342	19	0.322	19	0.200	11
WP6	0.406	10846	10796	50	0.406	50	0.200	24
WP7	0.370	6723	6662	61	0.370	61	0.200	33
WP8	0.310	6034	5967	67	0.310	67	0.200	43
GAS STEAM	0.550	72032	69063	2969	0.200	1079	0.100	540
OLD GT	0.410	278	233	46	0.410	46	0.410	46
Dupont Cogen	0.060		482	-482	0.060	-482	0.060	-482
REFURB	0.250	64	55	10	0.200	8	0.100	4
DUPONT Boiler	0.223	927		927	0.050	208	0.038	156
non-Dupont system		130084	126758	3326		1435		745
Total HL&P System		130084	127240	2845		954		264
Total		131011	127240	3772		1161		420

EXHIBIT PLC-5

Table 5: Correction of HL&P 7/92 Emissions Analysis

	HL&P Emit #/MMBTU	W/O	With	Savings	Emits w/ CAAA Ph 1 #/MMBTU	Delta	Emits w/ CAAA Ph 2 #/MMBTU	Delta
Limestone 1	0.51	14666	14660	6	0.510	6	0.200	2
Limestone 2	0.48	12348	12346	2	0.480	2	0.200	1
WA Parrish 5	0.322	7373	7369	4	0.322	4	0.200	2
WA Parrish 6	0.406	10926	10908	18	0.406	18	0.200	9
WA Parrish 7	0.37	6871	6851	20	0.370	20	0.200	11
WA Parrish 8	0.31	6233	6208	25	0.310	25	0.200	16
GAS STEAM	0.55	86008	82810	3198	0.200	1163	0.100	581
OLD GT	0.41	588	582	6	0.410	6	0.410	6
Dupont Cogen	0.06		482	-482	0.060	-482	0.060	-482
REFURB	0.25				0.200	0	0.100	0
New Gas CC	0.02	7	0	7	0.020	7	0.020	7
DUPONT Boiler	0.2232	927		927	0.050	208	0.038	156
non-Dupont system		145020	141734	3279		1244		629
Total HL&P System		145020	142216	2797		762		147
Total		145947	142216	3724		970		303

Table 6: Correction of HL&P 5/92 Emissions Analysis, w/ CC

	HL&P Emit #/MMBTU	W/O Dupont, w/ CC	With Dupont, w/o CC	Delta	Emits w/ CAAA Ph 1 #/MMBTU	Delta	Emits w/ CAAA Ph 2 #/MMBTU	Delta
L1	0.510	14652	14645	7	0.510	7	0.200	3
L2	0.480	12096	11996	100	0.480	100	0.200	42
WP5	0.322	7360	7342	19	0.322	19	0.200	11
WP6	0.406	10845	10796	49	0.406	49	0.200	24
WP7	0.370	6722	6662	60	0.370	60	0.200	33
WP8	0.310	6033	5966	67	0.310	67	0.200	43
GAS STEAM	0.550	69382	69063	318	0.200	116	0.100	58
OLD GT	0.410	234	233	1	0.410	1	0.410	1
New CC	0.020	85	0	85	0.020	85	0.020	85
Dupont Co	0.060	0	482	-482	0.060	-482	0.060	-482
REFURB	0.250	55	55	1	0.200	0	0.100	0
DUPONT Bo	0.223	927	0	927	0.050	208	0.038	156
non-Dupont system		127466	126758	708		505		301
Total HL&P System		127466	127240	226		23		-181
Total		128393	127240	1153		231		-25

Table 7: Computation of the Cost of NOx Control from
Construction of the DuPont Project

		Source
NPV fixed costs 1991$	$166 million	Figure CSG-S3
inflated to 1995 @ 4%	$243 million	
real-levelized @	6.7%	
	$16.3 million/yr	
energy/yr	1,316 GWH	
fixed cost/MWH	$12.38 /MWH	
fuel cost $/MMBTU	$2.52	Griffey WP 58
Dupont heat rate	7.03 MMBTU/MWH	Proscreen
Dupont fuel cost $/MWH	$17.72 /MWH	
Dupont variable O&M	$1.23 /MWH	Proscreen
Typical gas steam		
heat rate	10 MMBTU/MWH	Proscreen
fuel cost	$25.20 /MWH	
var O&M	$1.23 /MWH	varies: used Dupont
Savings	$7.48 /MWH	
Net cost	$4.89 /MWH	
Net Cost Annualized	$6.4 million/yr	
Emission reduction per HL&P	3772 T/yr	
Cost of reduction	$1,706 /Ton	
Reduction w/ Combustion Controls	1161 T/yr	
Cost of reduction	$5,543 /Ton	

EXHIBIT PLC-8

AFFIDAVIT

THE STATE OF MASSACHUSETTS §

COUNTY OF SUFFOLK §

BEFORE ME, the undersigned Notary Public, on this date personally appeared Paul L. Chernick, who, being duly sworn, deposed and stated:

1. "My name is Paul L. Chernick. I am over twenty-one (21) years of age, am competent to make this Affidavit, and have personal knowledge of all matters discussed herein.

2. I hereby swear and affirm that, to the best of my knowledge and belief, all statements made in the attached foregoing instrument are true and correct."

Paul Chernick

SUBSCRIBED AND SWORN to before me this 25th day of September, 1992.

Sheila Rourke

Notary Public in and for the
Commonwealth of Massachusetts

My Commission Expires 3-28-97