PGW St. No. 11

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

TESTIMONY OF

PAUL CHERNICK
Resource Insight, Inc.

ON BEHALF OF
PHILADELPHIA GAS WORKS

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I. Identification & Qualifications

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

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

Q: Summarize your professional education and experience.

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

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

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

Q: Have you testified previously in utility proceedings?

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

Q: Have you testified previously before the Pennsylvania Public Utilities Commission (the PUC)?

A: Yes. I testified in the following dockets:

- Pennsylvania PUC R-842651, a Pennsylvania Power and Light rate case, on the need for, and operating costs and rate effects of, the Susquehanna 2 nuclear plant, on behalf of the Pennsylvania Consumer Advocate.
- Pennsylvania PUC R-850152, a Philadelphia Electric Rate Case, on rate effects of Limerick 1, on behalf of the Utility Users Committee and University of Pennsylvania.
- Pennsylvania PUC R-850290, on auxiliary rates for Philadelphia Electric, on behalf of the University of Pennsylvania and Amtrak.
- Pennsylvania PUC I-900005, R-901880, on electric-utility DSM and DSM-cost recovery, for the Pennsylvania Energy Office.
- Pennsylvania PUC Docket No. 00061346, on real-time pricing for Duquesne Lighting, on behalf of PennFuture.
- Pennsylvania PUC Docket No. R-00061366, et al., rate-transition-plan proceedings of Metropolitan Edison and Pennsylvania Electric, on real-time and time-dependent pricing, on behalf of PennFuture.

Q: Please summarize your experience in the development of avoided costs.

A: I have developed or modified estimates of electric avoided costs for numerous electric utilities; many of these estimates are listed in my resume. I estimated statewide avoided costs for Vermont in 1997, and regional avoided generation costs for all of New England for a consortium of utilities in 1999, 2001, 2007, and 2009.[1] I also described the process of deriving avoided costs in a report to the Pennsylvania Energy Office in 1993.[2] I developed gas avoided costs for Boston Gas (now part of KeySpan) in the late 1980s and early 1990s, for Washington Gas Light in the 1990s, in the New England consortium reports (above) in 1999 and 2001, in two 2006 reports for NYSERDA ("Natural Gas Energy Efficiency Resource Development Potential in Con Edison Service Area" and "Natural Gas Energy Efficiency Resource Development Potential in New York"), in New York's energy-efficiency rulemaking, and for Peoples Gas Company.

Q: Please summarize your experience in the planning and promotion of energy-efficiency programs.

A: I have testified on demand-side-management potential, economics and program design in approximately 54 proceedings since 1980. In the 1990s I participated in several collaborative efforts among utilities, consumer advocates, and other parties, including those for PEPCo, BG&E, Delmarva Power, Potomac Edison,

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1 These are, respectively, "Avoided Energy Supply Costs for Demand-Side Management in Massachusetts" (1999), "Updated Avoided Energy Supply Costs for Demand-Side Screening in New England" (2001), "Avoided Energy Supply Costs in New England: 2007 Final Report" (2007), and "Avoided Energy Supply Costs in New England: 2009 Final Report" (2009), all for the Avoided-Energy-Supply-Component Study Group, c/o National Grid Company (Northborough, Massachusetts).

2 That work was in "Qualifying the Benefits of Demand Management," the fifth volume of the five-volume *From Here to Efficiency: Securing Demand-Management Resources* published in 1992 and 1993 by the Pennsylvania Energy Office.

Washington Gas Light, Central Vermont Public Service, Vermont Gas, and NYSEG. More recently, I have participated in collaboratives related to Con Edison's gas- and electricity-efficiency programs and New York statewide program rules and objectives.

Q: Please summarize your experience regarding recovery of utility energy-efficiency program costs and associated revenue losses.

A: I first proposed a combined revenue-stabilization and conservation-funding mechanism in testimony on alternatives to the Seabrook nuclear power plant before the New Hampshire Public Utilities Commission in Docket No. DE1-312 in October 1982. My qualifications list a number of subsequent engagements related to ratemaking for energy efficiency, including recovery of direct costs and lost revenue.

I have supported broader revenue stabilization than proposed by the utilities in some cases (e.g., in Ontario), and proposed modifications to utility decoupling proposals in other situations (e.g., for Con Edison's electric sales, Vectren's Indiana gas territories). I have also worked on issues of cost recovery in collaborative efforts among utilities, consumer advocates, and other parties, including Con Edison's continuing gas revenue-per-customer decoupling collaborative.

II. Introduction

Q: On whose behalf are you testifying?

A: My testimony is sponsored by Philadelphia Gas Works (PGW).

Q: What is the purpose of your testimony?

A: I describe the derivation of PGW's avoided gas costs and support PGW's proposal for the recovery of program expenditures and lost revenues resulting from the conservation program proposed in the testimony of PGW Witness John Plunkett.

Q: Please summarize the remainder of your testimony.

A: Section III describes my derivation of avoided costs for gas and electricity.

Section IV describes the need for and operation of the Efficiency Cost Recovery Adjustment, by which PGW would recover its costs related to encouraging energy efficiency and maintain its financial stability.

Section V describes my derivation of the rate impacts of DSM spending.

III. Development of Avoided Costs

A. Avoided Gas Costs

Q: Did you develop the avoided gas costs used in the economic screening of PGW's proposed energy-efficiency and conservation programs?

A: Yes.

Q: Please describe your approach.

A: The purpose of avoided costs is to estimate the benefit to consumers of reduced energy usage. The major benefit is the reduction of the quantity of gas required to serve customer loads and of the associated pipeline and storage capacity required to deliver the gas to the PGW citygate at the times customers require it. This benefit does not necessarily equal the rate paid by the customer to the utility or a natural-gas supplier in a particular month. The market price of gas varies daily or even hourly, while the gas charges may average out costs over a range of load shapes and a number of months. For customers using gas supplied by PGW, all the costs of gas used by customers will flow through to customers and all the costs saved from energy efficiency will similarly flow through to customers. Customers served by natural-gas suppliers may pay a contract rate in the short term, but those rates are likely to be adjusted over time to reflect the costs of serving the customer's actual load.

I outline my approach in this testimony. Exhibit PLC-2 presents the derivation of avoided costs in greater detail.

Q: **How did you project the cost of gas or the benefit of reduced gas consumption?**

A: I began with the monthly forward prices for gas at Henry Hub and added the monthly forward price for delivery of gas from Henry Hub to the PGW citygate. These are the prices in the market for equal amounts of gas delivered in each day of the month. For baseload efficiency measures, which save the same amount of energy every day, the avoided commodity cost is simply the average of the delivered gas prices across months, weighted by the number of days in the month.

For measures that save energy in proportion to heating loads, the computation is somewhat more complicated. Heating loads tend to be highest in the high-priced months, and in the highest-price days within the month. Indeed, the total heating requirement for customers in the Northeast and across the continent is the most important factor in driving price differences within a month. I assumed that the savings from heating measures would be distributed across months in proportion to normal monthly heating degree days. Within each month with significant heating load, I estimated the historical ratio of prices weighted by normal heating degree days to the simple average of the prices; see Exhibit PLC-2. The intra-month correlation of heating load and gas price results in the value of avoided heating load exceeding the value of avoided baseload by roughly 1–5% in various heating months. The avoided commodity cost for space-heating load is thus more than the cost for baseload measures. This is due to both the greater gas usage of heating in the higher-priced months and due to the greater gas usage of heating in the higher-priced days within each month.

Q: Does PGW actually purchase and sell gas in the spot market?

A: Yes. I understand that those transactions are relatively small, compared to PGW's total sales, and primarily for balancing purposes. Spot transactions set the short-run marginal cost of additional usage. Most of PGW's gas supply comes from longer-term contracts for commodity, pipeline capacity, and storage.

Q: Could PGW's avoided costs be estimated from the costs of those contracts?

A: Yes, in principle. I developed my earliest estimates of gas avoided costs, for Boston Gas in the 1980s, by estimating the effect of load reductions on specific purchases of capacity and commodity. In those days, before the competitive gas market had developed fully, contract prices were essentially the only measure of avoidable costs. Estimation of the avoided costs required Boston Gas to redispatch its entire system—pipeline purchases, storage injections and withdrawals, LNG liquefaction and withdrawals, propane injection—on a daily basis for different levels of heating load, reflecting the contracts that would be reduced with lower demand levels. This is a complicated process, and the utilities I have worked with since then (the New England and New York utilities and now PGW) have not chosen to pursue that modeling approach.

Q: Why have you used the market-valuation approach to estimating market prices, rather than the utility-specific supply approach?

A: Both practical and theoretical considerations inform this choice. Practically, the utility-supply approach is difficult to implement. Modeling the effects of load reductions on dispatch over time is quite complicated. Such an analysis would start with estimation of base-case gas dispatch, including exactly how much of each supply will be (1) used to meet daily load, (2) injected into storage or liquefied, (3) withdrawn or vaporized, or (4) sold off-system at various points from production to the PGW citygate. A reduction in load with a particular shape (such as heating load, proportional to heating degree days) would change the amount of daily gas that PGW and third-party suppliers would purchase at the production areas, and the amount that would be transported, injected into storage, liquefied, withdrawn, vaporized, sold off-system, and so on. Both the change in the dispatch and the cost reductions would depend on how PGW and other suppliers adjust their commodity, pipeline-capacity, and storage-capacity entitlements at various locations, from production to the PGW citygate in the short and long term, including renegotiation, resale, release, or allowing contracts to expire.[3]

Fortunately, with the emergence of public markets for gas delivered at particular locations, this complexity is not necessary. Theoretically, PGW's long-term avoided cost should be very close to the market price of supply. The avoidable costs of production-area commodity contracts—which may be avoided by some combination of reselling the gas, negotiating early termination or reduction of contracts, and not signing new contracts—would likely be very similar to the forward costs of gas at Henry Hub. If the market prices of supply are significantly greater than those in PGW's contracts, PGW should be retaining the contracts and selling gas into the higher-priced market, so that improved energy efficiency avoids the market price. If the market prices of supply are

[3] Many of the specific products that PGW might resell or renegotiate are not widely traded, further complicating the analysis.

significantly less than those of PGW's contracts, PGW should be allowing those contracts to expire and purchasing more supply through the markets; again, the benefit of reduced load is a reduction in market purchases.

Q: How did you project avoided costs beyond the period for which you have forward prices?

A: I had monthly forwards from NYMEX for the price differential from Henry Hub to the Philadelphia citygate for 2009 through 2012. Thereafter, I escalated the differential in proportion to the escalation in the Henry Hub price through 2020, the end of NYMEX forwards for Henry Hub. After 2020, I assumed that the avoided costs would be constant in real terms. I assumed that future inflation would be 2%.

Q: Other than commodity delivered to the citygate, does energy efficiency allow PGW to avoid any other costs?

A: Yes. In addition to providing gas to meet normal weather, PGW must provide enough reserve capacity to meet loads under design conditions, including both a design day with 65 heating degree days and a design winter with heating loads approximately 19.4% greater than normal. I estimated the cost of that reserve as the price of PGW's contracts supporting its most expensive storage supply (Equitrans) times the percentage increase in heating load between normal and design winters. I took the fixed cost of the Equitrans supply as $2.40/Dth, from Schedule SDS-8 of PGW's gas-cost-rate supporting documentation filed on June 2008. Exhibit PLC-3 shows my computation of normal heating sendout (42.5 million Dth) and the design-winter sendout increment (8.3 million Dth). As shown in Exhibit PLC-2, 0.194 Dth of peaking supply at $2.40/Dth of peaking results in a peaking-reserve cost for heating load of about $0.50/Dth. Baseload does not increase under design conditions, and so has no peaking-reserve cost.

Q: Please summarize your estimates of avoided gas costs.

A: Table 1 provides that summary. It is important to note that these avoided costs do not include any costs related to the carbon caps in the legislation that has passed the House of Representatives (Waxman-Markey) and has been introduced in the Senate (Boxer-Kerry). Those carbon caps could significantly increase the value of energy efficiency and conservation, since future utility DSM programs are likely to be counted as offsets and allocated credits and since both bills would require gas utilities to hold allowances starting in 2016.

Table 1: Summary of Avoided Gas Costs (2008 Dollars per MMBtu)

Year	Baseload	Space heating	Water heating
2010	$7.20	$8.57	$7.54
2011	$7.31	$8.67	$7.65
2012	$7.27	$8.58	$7.60
2013	$7.24	$8.54	$7.57
2014	$7.27	$8.57	$7.60
2015	$7.35	$8.66	$7.68
2016	$7.48	$8.81	$7.81
2017	$7.68	$9.03	$8.02
2018	$7.94	$9.32	$8.29
2019	$8.08	$9.47	$8.43
2020	$8.07	$9.46	$8.42
2021	$8.10	$9.50	$8.45
2022	$8.20	$9.61	$8.55
2023	$8.48	$9.92	$8.84
2024	$8.81	$10.29	$9.18
2025	$9.11	$10.62	$9.49
2026	$9.41	$10.95	$9.80
2027	$9.67	$11.24	$10.06
2028	$9.86	$11.45	$10.26
2029	$10.03	$11.63	$10.43
2030	$10.08	$11.70	$10.48
2031	$10.28	$11.92	$10.69
2032	$10.28	$11.92	$10.69
2033	$10.28	$11.92	$10.69

Q: Do energy-efficiency and conservation investment have other benefits, beyond those you have quantified?

A: Yes. PGW's energy-efficiency programs and resulting reductions in gas load would perform the following beneficial functions:

- create local jobs for local businesses in implementing the programs, from distributing equipment and materials to installation and inspections.
- reduce wholesale-market gas prices, particularly in the Northeast. While this is a small price effect per Ccf, it has that effect over large amounts of retail sales and the large amounts of electric energy that is priced at the marginal costs of gas-fired generators.
- provide a model for energy-efficiency programs for other Pennsylvania gas utilities, which would directly benefit the customers of those utilities and multiply the market-price benefits to consumers.
- improve customer comfort.
- potentially improve PGW cash flow, reducing the need for reliance on borrowing.
- improve customer ability to pay.
- leave customers with additional cash to be spent in Philadelphia, stimulating the local economy.

Furthermore, while most of PGW's system is experiencing falling loads and hence needs no capacity-related upgrades, there are areas in which PGW does require increased delivery capacity due to local growth, mostly to accommodate new interruptible loads. The distribution capacity freed up by energy efficiency may allow PGW to avoid some system upgrades, depending on the location and magnitude of the energy-efficiency and conservation investment and of the added loads.

Philadelphia Gas Works has not quantified these effects, but they are all properly included in the benefits of an energy-efficiency and conservation program.

B. Avoided Electric Costs

Q: Why are avoided electric costs relevant to the evaluation of PGW's energy-efficiency programs?

A: Gas energy-efficiency measures can increase or decrease electricity use. For example, some high-efficiency boilers use more electricity than standard-efficiency boilers. Tradeoffs between gas and electric savings arise in choosing between window designs that admit solar energy in the winter and those that keep out sunshine in the summer. On the other hand, building shell measures (wall and roof insulation, tighter windows), setback thermostats, and duct sealing in gas-heated buildings are likely to decrease electric use both for circulating heat (with pumps and/or fans) and for summer cooling. Accurately evaluating the cost-effectiveness of the gas energy-efficiency and conservation programs requires valuation of the changes in electricity use, along with all other costs and benefits.

In addition, while PGW (or any efficiency provider) is in the customer's premises, there may be opportunity for installing efficiency and conservation measures for other service providers, in this case the electric and water utilities. The incremental cost of having PGW install compact fluorescents when they are on site (e.g., to insulate, perform air sealing, or wrap water heaters and pipes) is much less than the cost of sending contractors to separately perform the same task for the electric company's customers.

Philadelphia Gas Works intends to attempt to work out cooperative arrangements with all energy suppliers and DSM contractors to reduce redundancy in site visits and coordinate support and incentives for construction and custom retrofits.

Q: How did you estimate electric avoided costs?

A: My computation of avoided energy costs started with NYMEX monthly forward prices for PJM on- and off-peak energy through 2013. To these flat monthly prices at the PJM Western Hub, I added adjustments for load shape, congestion (both from the PJM "2007 State of the Market Report," Market Monitoring Unit, March 11, 2008), and marginal losses. I then weighted the market energy costs across months, to derive an average annual avoided energy cost for each gas year. Beyond 2014, I assumed that the avoided energy costs would rise at the rate forecast by the Energy Information Administration (2009).

I did not explicitly recognize any effects of carbon caps or changing fuel mix in the future.

To the energy costs, I added capacity costs at the market-clearing price applicable to electric service. Since PJM obtains capacity on a locational basis, the capacity price may be essentially uniform across the entire PJM RTO, or may vary between regions. The capacity price applicable to the Philadelphia region was the Eastern MAAC zone for 2008/09 and 2009/10, the PJM RTO as a whole for 2010/11 and 2011/12, and Eastern MAAC again in 2012/13. I assumed that the capacity price in 2013/2014 would be the average of the previous auction prices ($71/kW-year, including reserve margin) in nominal dollars, without inflating the earlier prices. After 2013/14, I escalated the capacity price at inflation.

The results of my computations are summarized below in Table 2.

Table 2: Summary of Estimate of Avoided Electric Costs

	Nominal Dollars			
Gas Year	*Energy* ($/MWh)	*Capacity* ($/kW-yr)	*Total at 65% CF* ($/MWh)	**Real Dollars** (2008$/MWh)
2010/11	$65	$74	$78	$74
2011/12	$69	$55	$78	$73
2012/13	$69	$62	$80	$73
2013/14	$72	$71	$84	$75
2014/15	$75	$73	$88	$77
2015/16	$79	$74	$92	$79
2016/17	$84	$76	$97	$82
2017/18	$89	$77	$103	$85
2018/19	$96	$79	$109	$89
2019/20	$102	$80	$116	$92
2020/21	$105	$82	$119	$93
2021/22	$106	$84	$120	$92
2022/23	$110	$85	$125	$94
2023/24	$116	$87	$131	$96
2024/25	$125	$89	$141	$101
2025/26	$134	$90	$150	$106
2026/27	$143	$92	$159	$110
2027/28	$153	$94	$169	$115
2028/29	$162	$96	$179	$119
2029/30	$170	$98	$187	$122

These are very simple electric-avoided-cost placeholders. As electric companies implement energy-efficiency programs, and to the extent those efforts are coordinated with PGW's programs, the electric utilities will likely also develop more-sophisticated electric avoided costs, differentiated by season and time of use and reflecting avoided T&D costs. My simplified estimate of avoided electric costs probably understates avoided costs for most electric efficiency measures.

IV. Efficiency-Cost-Recovery Mechanism

Q: Please describe the proposed Efficiency-Cost-Recovery Mechanism.

A: The Efficiency-Cost-Recovery Mechanism (ECRM) would operate much like the existing Universal Service and Energy Conservation Surcharge. The rate would be revised each quarter, at the beginning of September, December, March, and June, and PGW would file supporting documentation for its revised rate. PGW would respond to any questions that the Commission Staff or other parties may have regarding the filings, through written responses and/or technical meetings. Each quarterly adjustment to the ECRM would be a constant dollars-per-Ccf increment for the subsequent twelve months.

On approximately March 1 of each year, PGW would make a formal reconciliation filing to be rolled into the September 1 adjustment, subject to Commission approval.

Q: What costs would the ECRM recover?

A: The ECRM would include recovery of PGW's program expenditures and revenues lost due to PGW's efficiency and conservation programs.

Q: Would the ECRM fully recover PGW's costs?

A: No. PGW does not propose to include any interest credit between the time money is spent and the time collection starts, or for the delay in recovery over twelve months. These carrying costs would be offset by reductions in cash working capital required for gas purchases. The relative magnitude of the increases and decreases in carrying costs will depend on the duration between rate cases, the amount of energy saved per dollar invested, the fraction of conservation that is heating-related, weather, and other factors. PGW does not seek to recover revenue lost as a result of response to advertising and other media messages promoting conservation nor revenue lost as a result of market changes resulting from the PGW program and its cooperative efforts with other utilities and government entities. While related to PGW efforts, these revenue losses are simply too difficult to measure.

A. Program Expenditures

Q: How would the structure of the ECRM differ from the Universal Service and Energy Conservation Surcharge?

A: The ECRM would vary by class. The Universal Service and Energy Conservation Surcharge (USC) would continue to recover the costs of energy-efficiency and conservation services to low-income residential customers, i.e. the Conservation Works Program, from all other firm classes. The costs related to customers other than low-income residential customers would be tracked separately for the following three firm classes served by the energy-efficiency programs:

- residential and public housing customers on Rate GS and on Rate PHA,
- commercial and municipal customers on Rate GS and on Rate MS,
- industrial customers on Rate GS.

Q: How does PGW propose to fund its energy-efficiency and conservation programs?

A: The programs would be funded through the following two sources:

- In many programs, the participants will pay part of the initial cost of the measures that serve them, either to PGW or to a third party implementing the measures.
- The residual direct program costs would be recovered from ratepayers, through the ECRM.

B. Lost Revenues

Q: Other than the costs of operating the programs, how do energy-efficiency and conservation programs affect PGW's earnings and liquidity?

A: The principal purpose of energy-efficiency programs is to reduce customer costs by reducing the usage of commodity. Since PGW flows through the costs of commodity to customers, reduced commodity use has little effect on PGW's financial condition, other than indirectly through the effect on cash working capital. But in addition to commodity, PGW charges for distribution costs as a function of consumption, at about 38¢/Ccf for MS, 62¢ for residential GS, and about 52¢/Ccf for PHA and the non-residential GS classes. Since distribution costs are almost all fixed in the short term, every Ccf of gas that a customer does not use due to an energy-efficiency and conservation program reduces PGW's earnings and cash flow.

The better PGW does at reducing its customers' energy usage and bills, the worse off PGW would be under current ratemaking. This disincentive remains one of the major barriers to more effective energy policy in many states.

Q: How does PGW propose to resolve this conflict?

A: Philadelphia Gas Works proposes to recover its lost revenues for all customers, other than those in the Customer Responsibility Program (CRP), through the ECRM. Due to the operation of the CRP, efficiency measures delivered to CRP customers will not result in reductions in the participating customer's bill, but will instead reduce the Universal Service Surcharge borne by all non-CRP firm customers. Those revenues will be permanently lost to PGW, and will increase until the next rate proceeding, when rates will be reset and the losses will start to accumulate once more.

Q: How would the lost-revenue portion of the ECRM work?

A: The basic approach in computing lost revenues comprises the following steps, for each measure covered by an energy-efficiency and conservation program:

1. Count the number of measures installed under the program.
2. Estimate the annual sales effects of each measure.
3. Estimate the percentage of the savings that would have occurred without the program, and that therefore do not reflect any program-related revenue loss.[4]
4. Estimate the extent of spillover from the program to non-participants, such as by increasing supply of efficient equipment in warehouses and stores.
5. Determine the rate per Ccf for the sales reduction, which may require, for example, tracking the number of participants in a boiler program who are on residential Rate GS, public-housing Rate GS, commercial Rate GS, Rate PHA, and Rate MS.
6. Compute when the savings from each measure would start, given both the installation schedule and the seasonality of load.
7. Compute the resulting lost revenues.

Q: What factors would be considered in estimating the sales effects of each measure?

A: The estimated effect on sales may depend on the following factors:

- the size of the equipment affected, such as the volume of the water heater or the Btu output rating of a furnace;
- building size;

[4] The participants who would have invested in efficiency without the program are often called "free riders." That terminology incorrectly suggests that they are somehow getting a better deal than other participants.

- household size, especially for water heaters, dishwashers, and clothes washers;
- pre-measure usage;
- efficiency of the rest of the system, such as the effect of the building envelope on the sales reduction from a more-efficient heating system.

Q: Would all of these variables be determined for each installation?

A: Not all of them. PGW will establish a tracking system to record the number of rebates and installations, information on the size and model number of equipment installed, customer rate class, and other detailed data. Variables that would not be feasible to track for each installation (such as household size in a rebate program) would be determined from limited samples of participants.

Q: Is this approach used in other jurisdictions?

A: Yes. Lost-revenue-adjustment mechanisms are used for electric and/or gas utilities in Ontario, Massachusetts, Connecticut, Vermont, Ohio, Kentucky, and Indiana, Maryland, New Jersey, and New York.

Q: Has PGW developed detailed protocols for the tracking system and the estimation of lost revenues?

A: Not yet. PGW intends to develop the tracking system and the lost-revenue formulas in parallel with implementation of the efficiency programs. In my experience, the development of programs, tracking system, and lost-revenue-estimation procedures generally occur in parallel.

This process will probably be most-effectively pursued through a collaborative effort with the Public Utility Commission Staff, the Consumer Advocate, the Office of Small Business Advocate, and other parties with expertise in energy-efficiency monitoring and evaluation. In particular, it is important to resolve cooperatively the lost-revenue inputs to the extent possible.

Arguing about these issues in an ECRM proceeding may push PGW and other parties into positions based on the lost-revenue litigation, rather than identifying the most-effective measures and delivery mechanisms to reduce energy consumption, and on the best estimates of savings from those measures and mechanisms.

Q: Would the lost-revenue computation be reset at some point?

A: Yes. In each rate proceeding, a new projection of pro-forma revenues is used to set rates. Accordingly, any lost-revenue amount in the ECRM would be eliminated at the effective date of the new rates.

Q: What are the alternatives to lost-revenue recovery?

A: Were the lost-revenue recovery not implemented, the alternatives would be as follows:

- Continue with the existing ratemaking process;
- Conduct annual rate cases, projecting sales based on DSM underway;
- Roll all distribution costs into customer charges, so that PGW's distribution revenues are independent of sales;
- Implement a revenue-stabilization mechanism;
- Minimize investment in conservation.

Q: What would be the consequences of maintaining the current approach to ratesetting for PGW?

A: Promoting energy efficiency in that case may result in financial distress for PGW, forcing it to curtail programs pending a rate increase. In the absence of those programs, customer gas bills would be greater than necessary.

Q: What would be the consequences of conducting annual rate cases and projecting sales to reflect DSM plans?

A: These continual rate cases would impose large burdens on PGW, the Commission, and other parties. The demands of a rate case compete for the attention of PGW management, and hence impede their ability to implement improvements and innovations, not to mention routine obligations. PGW may also be forced to slow its implementation of energy-efficiency and conservation programs to live within the revenues projected in the rate case and used to set distribution rates.

Q: What would be the effect of rolling all distribution costs into customer charges?

A: That approach would violate the principle of cost causation, since a significant portion of PGW's distribution costs are driven by load levels. It would also eliminate customers' opportunity to reduce their distribution bills, seriously affect the smaller customers in each rate class by materially increasing their bills, and charge very different amounts to customers based solely on their classification as commercial or industrial customers.

Q: How would a revenue-stabilization mechanism operate?

A: A revenue-stabilization or decoupling mechanism would compare actual revenues to a target revenue level, and adjust rates to flow the difference to PGW or its customers.

Q: Would a revenue-stabilization mechanism have any advantages compared to the proposed lost-revenue mechanism?

A: Yes, least three. First, a revenue-stabilization mechanism would eliminate any weather-related over- and under-collections not captured by the existing weather adjustment (e.g., the effects of wind speed, cloud cover, snow cover, etc.).

Second, the projection of sales in a rate proceeding would no longer be of great import. Were the forecast overstated, the revenue-stabilization charge would increase; if the understated, the revenue-stabilization charge would decrease and perhaps even become negative. Removing the sales forecast from a rate proceeding should reduce the cost and burden for PGW, the Commission Staff, the Consumer Advocate, the Office of Small Business Advocate, and other parties.

Third, lost-revenue adjustments also generally cannot account for PGW's role in providing information and other indirect support for energy-efficiency and conservation investments, for the effects of market-transformation programs, or the effects of other programs encouraged or supported by PGW. In the case of programs operated by electric companies or various government agencies, PGW's provision of billing data, customer contacts, and other services may be critical to success of the programs. The success of PGW in supporting those programs may undermine PGW's financial stability, even with a lost-revenue adjustment. A revenue-stabilization mechanism does not differentiate among the possible reasons for differences between target and actual revenues, and hence would protect PGW's distribution revenues from the effect of efficiency and conservation programs, regardless of who administers those programs.

Q: Do other gas utilities have revenue-stabilization mechanisms in place?

A: Yes. Some thirteen states have some sort of revenue-stabilization mechanism in place for a total of nearly thirty utilities. In California, these provisions have been in place for more than 25 years. In addition, the Massachusetts Department of Public Utilities has approved revenue stabilization for all utilities in that state, pending individual filings, and the Nevada PSC has submitted proposed revenue-stabilization regulations for legislative review.

Q: Do any of the jurisdictions near Pennsylvania use revenue-stabilization mechanisms?

A: Yes. In New Jersey, for example, South Jersey Gas and New Jersey Natural Gas reached a settlement with the Rate Counsel and Board Staff, establishing (among other things) a set of conservation programs and revenue stabilization, with target revenues set at the number of customers times baseline revenue per customer for each class. The utilities' collection of revenues under this Conservation Incentive Program is limited to the effects of weather plus demonstrated savings in gas costs from release of excess capacity, reduced purchases of gas, avoided increases in fixed supply costs, and other reductions.

Q: Why are you not proposing a revenue-stabilization mechanism?

A: Philadelphia Gas Works chose to propose the more-conservative lost-revenue approach to increase the chances of consensus agreement on lost-revenue recovery.

V. Estimate of Lost Revenues

Q: Please describe your analysis of the impact of DSM spending on lost revenues, average rates, and bills.

A: My analysis estimates average rates and bills for each major customer class for a base scenario that assumes no new DSM spending, and then estimates the effect on class-average rates and bills from forecasted DSM spending and associated reductions in customer usage. I forecast average rates and bills, both with and without DSM-related impacts, over a five-year period starting in fiscal year 2010.

Q: How do you derive the without-DSM average rates and bills for each customer class?

A: I calculate without-DSM average rates and bills based on the Company's current budget forecast of revenues, sales, and number of customers. For each customer class, and for each fiscal year from 2010 through 2014, the average bill is calculated as revenues from firm heating, non-heating, transport customers divided by the number of those customers. Likewise, the average rate is calculated as class revenues from firm customers divided by sales to those customers.

Q: How do you account for the effects of DSM spending on average rates and bills?

A: I reflect these effects on average rates and bills by adjusting the forecast of revenues and sales to account for DSM-related expenditures and savings. Specifically, I make the following adjustments to revenues for each customer class and for each forecast year:

- *increase,* to reflect the estimate of DSM-program spending for that class and year;
- *decrease,* to account for reductions in gas-commodity costs from DSM-related savings estimated for that class in that year.

In addition, I adjust forecasted revenues to reflect changes in recovery of the Universal Service Charge from non-CRP customers that result from DSM spending on CRP customers. For the purposes of this calculation, I assume that DSM spending on CRP customers has no effect on the amount of revenues recovered from those customers. Instead, I adjust the USC revenues recovered from non-CRP customers to reflect the following factors:

- recovery of direct DSM spending on CRP customers,
- reductions in gas-commodity costs attributable to CRP DSM savings,

- reductions in CRP distribution-charge revenues that are recovered from non-CRP customers through the USC.[5]

Finally, I reduce forecasted sales for each customer class and forecast year by estimated DSM-related savings. Average rates and bills with DSM are then calculated in the same fashion as in the without-DSM case, but using the revenue and sales forecasts as adjusted to reflect the effects of DSM spending.

Q: Please summarize your estimates of lost revenues.

A: Table 3 provides those estimates, assuming no rate case occurs through 2014-15. The "total not including CRP" would be recovered through the ECRM, while PGW would absorb the remainder of the "total" line.

Table 3: Summary of Estimated Lost Revenues

Fiscal Year	**2010–11**	**2011–12**	**2012–13**	**2013–14**	**2014–15**
Non-Low-Income Residential Customer	$96,772	$505,745	$1,293,167	$2,298,727	$3,008,409
CRP (Low Income)	469,354	1,312,844	2,082,352	2,880,463	3,418,393
Commercial Customers	17,301	88,629	230,301	448,013	626,875
Industrial Customers	405	1,821	5,260	12,745	19,825
Municipal Customers	2,742	29,244	86,720	154,436	199,807
Housing Authority—Rate GS	333	1,814	4,492	7,688	9,925
Housing Authority—Rate PHA	939	5,107	12,647	21,648	27,947
Total	$587,846	$1,945,203	$3,714,939	$5,823,720	$7,311,181
Total Not Including CRP	$118,491	$632,359	$1,632,587	$2,943,257	$3,892,788

Q: Is PGW claiming these amounts for recovery in its ECRM?

A: No. These are estimates based upon the proposed DSM program and current revenue projections. If and when PGW's DSM program is approved, PGW will submit a specific lost-revenue-calculation protocol and a specific proposed level of lost revenues, based upon the program as approved. PGW will then track its

[5] These revenue reductions are in fact lost revenues attributable to CRP DSM savings. However, these lost revenues will not be recovered through the lost-revenue surcharge.

lost revenues and will submit adjustments to the projections based on actual results.

Q: Does this conclude your testimony?

A: Yes.

Exhibit PLC-1

PAUL L. CHERNICK

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SUMMARY OF PROFESSIONAL EXPERIENCE

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

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

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

EDUCATION

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

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

HONORS

Chi Epsilon (Civil Engineering)

Tau Beta Pi (Engineering)

Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

PUBLICATIONS

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

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

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"A Utility Planner's Checklist for Least-Cost Efficiency Investment" (with John Plunkett) in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

Environmental Costs of Electricity (with Richard Ottinger et al.). Oceana; Dobbs Ferry, New York: September 1990.

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"Incorporating Environmental Externalities in Evaluation of District Heating Options" (with Emily Caverhill), *Proceedings from the International District Heating and Cooling Association 81st Annual Conference*, June 1990.

"A Utility Planner's Checklist for Least-Cost Efficiency Investment," (with John Plunkett), *Proceedings from the Canadian Electrical Association Demand-Side Management Conference*, June 1990.

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"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.

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

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"Green Resource Portfolios: Development, Integration, and Evaluation" (with Jonathan Wallach and Richard Mazzini). 2008. Report to the Green Energy Coalition presented as evidence in Ontario EB 2007-0707.

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

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"Review of Jersey Central Power & Light's 1992 DSM Plan and the Demand-Side Management Rules" (with Jonathan Wallach et al.); Report to the New Jersey Department of Public Advocate, June 1992.

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

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

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

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

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

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"Adding Transmission into New York City: Needs, Benefits, and Obstacles." Presentation to FERC and the New York ISO on behalf of the City of New York. October 2004.

"Plugging Into a Municipal Light Plant," With Peter Enrich and Ken Barna. Panel presentation as part of the 2004 Annual Meeting of the Massachusetts Municipal Association. January 2004.

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

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

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

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

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"Environmental Externalities: Current Approaches and Potential Implications for District Heating and Cooling" (with R. Brailove), International District Heating and Cooling Association 84th Annual Conference; June 1993.

"Using the Costs of Required Controls to Incorporate the Costs of Environmental Externalities in Non-Environmental Decision-Making." Presentation at the American Planning Association 1992 National Planning Conference; presentation cosponsored by the Edison Electric Institute. May 1992.

"Cost Recovery and Decoupling" and "The Clean Air Act and Externalities in Utility Resource Planning" panels (session leader), DSM Advocacy Workshop; April 15 1992.

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

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

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

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

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

"Quantifying and Valuing Environmental Externalities." Presentation at the Lawrence Berkeley Laboratory Training Program for Regulatory Staff, sponsored by the U.S. Department of Energy's Least-Cost Utility Planning Program; Berkeley, California, February 2 1990;

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

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

New England Conference of Public Utilities Commissioners, Environmental Externalities Workshop; Portsmouth, New Hampshire, January 22–23 1989.

"Assessment and Valuation of External Environmental Damages," New England Utility Rate Forum; Plymouth, Massachusetts, October 11 1985; "Lessons from Massachusetts on Long Term Rates for QFs".

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

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

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

"Review and Modification of Regulatory and Rate Making Policy," National Governors' Association Working Group on Nuclear Power Cost Overruns; Washington, D.C., June 20 1984.

"Review and Modification of Regulatory and Rate Making Policy," Annual Meeting of the American Association for the Advancement of Science, Session on Monitoring for Risk Management; Detroit, Michigan, May 27 1983.

ADVISORY ASSIGNMENTS TO REGULATORY COMMISSIONS

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

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

EXPERT TESTIMONY

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

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

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

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

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

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

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

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

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

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

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

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

7. **MDPU** 19845; Boston Edison Time-of-Use Rate Case; Massachusetts Attorney General; December 4 1979.

   Critique of utility marginal cost study and proposed rates; principles of marginal cost principles, cost derivation, and rate design; options for reconciling costs and revenues. Joint testimony with S.C. Geller. Testimony eventually withdrawn due to delay in case.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

18. **MDPU** 558; Western Massachusetts Electric Company Rate Case; Massachusetts Attorney General; May 1981.

    Rate design including declining blocks, marginal cost conservation impacts, and promotional rates. Conservation, including terms and conditions limiting renewable, cogeneration, small power production; scope of current conservation program; efficient insulation levels; additional conservation opportunities.

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

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

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

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

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

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

22. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1983 Automobile Insurance Rates; Massachusetts Attorney General; October 1982.

    Profit margin calculations, including methodology, interest rates, surplus flow, tax flows, tax rates, and risk premium.

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

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

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

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

25. **Connecticut Public Utility Control Authority** 830301; United Illuminating Rate Case; Connecticut Consumers Counsel; June 17 1983.

    Cost of Seabrook nuclear power plants, including construction cost and duration, capacity factor, O&M, capital additions, insurance and decommissioning.

26. **MDPU** 1509; Boston Edison Plant Performance Standards; Massachusetts Attorney General; July 15 1983.

    Critique of company approach and statistical analysis; regression model of nuclear capacity factor; proposals for standards and for standard-setting methodologies.

27. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1984 Automobile Insurance Rates; Massachusetts Attorney General; October 1983.

    Profit margin calculations, including methodology, interest rates.

28. **Connecticut Public Utility Control Authority** 83-07-15; Connecticut Light and Power Rate Case; Alloy Foundry; October 3 1983.

    Industrial rate design. Marginal and embedded costs; classification of generation, transmission, and distribution expenses; demand versus energy charges.

29. **MEFSC** 83-24; New England Electric System Forecast of Electric Resources and Requirements; Massachusetts Attorney General; November 14 1983, Rebuttal, February 2 1984.

    Need for transmission line. Status of supply plan, especially Seabrook 2. Review of interconnection requirements. Analysis of cost-effectiveness for power transfer, line losses, generation assumptions.

30. **Michigan PSC** U-7775; Detroit Edison Fuel Cost Recovery Plan; Public Interest Research Group in Michigan; February 21 1984.

    Review of proposed performance target for new nuclear power plant. Formulation of alternative proposals.

31. **MDPU** 84-25; Western Massachusetts Electric Company Rate Case; Massachusetts Attorney General; April 6 1984.

    Need for Millstone 3. Cost of completing and operating unit, cost-effectiveness compared to alternatives, and its effect on rates. Equity and incentive problems created by CWIP. Design of Millstone 3 phase-in proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

32. **MDPU** 84-49 and 84-50; Fitchburg Gas & Electric Financing Case; Massachusetts Attorney General; April 13 1984.

    Cost of completing and operating Seabrook nuclear units. Probability of completing Seabrook 2. Recommendations regarding FG&E and MDPU actions with respect to Seabrook.

33. **Michigan PSC** U-7785; Consumers Power Fuel Cost Recovery Plan; Public Interest Research Group in Michigan; April 16 1984.

    Review of proposed performance targets for two existing and two new nuclear power plants. Formulation of alternative policy.

34. **FERC** ER81-749-000 and ER82-325-000; Montaup Electric Rate Cases; Massachusetts Attorney General; April 27 1984.

    Prudence of Montaup and Boston Edison in decisions regarding Pilgrim 2 construction: Montaup's decision to participate, the Utilities' failure to review their earlier analyses and assumptions, Montaup's failure to question Edison's decisions, and the utilities' delay in canceling the unit.

35. **Maine PUC** 84-113; Seabrook 1 Investigation; Maine Public Advocate; September 13 1984.

    Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate effects. Recommendations regarding utility and PUC actions with respect to Seabrook.

36. **MDPU** 84-145; Fitchburg Gas and Electric Rate Case; Massachusetts Attorney General; November 6 1984.

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

37. **Pennsylvania PUC** R-842651; Pennsylvania Power and Light Rate Case; Pennsylvania Consumer Advocate; November 1984.

    Need for Susquehanna 2. Cost of operating unit, power output, cost-effectiveness compared to alternatives, and its effect on rates. Design of phase-in and excess capacity proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

38. **NHPUC** 84-200; Seabrook Unit 1 Investigation; New Hampshire Public Advocate; November 15 1984.

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

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

    Profit margin calculations, including methodology and implementation.

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

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

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

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

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

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

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

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

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

    Construction schedule and cost of completing Millstone Unit 3.

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

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

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

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

47. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1986 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; November 1985.

    Profit margin calculations, including methodology, implementation, modeling of investment balances, income, and return to shareholders.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

56. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1987 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; December 1986 and January 1987.

    Profit margin calculations, including methodology, implementation, derivation of cash flows, installment income, income tax status, and return to shareholders.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

    Rationale for demand-side management, and BG&E's problems in approach to DSM planning. Potential for cost-effective conservation. Valuation of environmental externalities. Recommendations for short-term DSM program priorities.

85. **Indiana Utility Regulatory Commission;** Integrated Resource Planning Docket; Indiana Office of Utility Consumer Counselor; November 1 1990.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Demand-side management cost recovery and incentive mechanisms.

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

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

110 **Florida Department of Environmental Regulation** hearings on the Power Plant Siting Act; Legal Environmental Assistance Foundation, December 1992.

Externality valuation and application in power-plant siting. DSM potential, cost-benefit test, and program designs.

111. **Maryland PSC** 8487; Baltimore Gas and Electric Company, Electric Rate Case; January 13 1993. Rebuttal Testimony: February 4 1993.

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

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

Economic analysis of proposed coal-fired cogeneration facility.

113.A. **Michigan PSC** U-10102; Detroit Edison Rate Case; Michigan United Conservation Clubs; February 17 1993.

Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

114. **Ohio PUC** 91-635-EL-FOR, 92-312-EL-FOR, 92-1172-EL-ECP; Cincinnati Gas and Electric demand-management programs; City of Cincinnati. April 1993.

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

115. **Michigan PSC** U-10335; Consumers Power Rate Case; Michigan United Conservation Clubs; October 1993.

Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

116. **Illinois Commerce Commission** 92-0268, Electric-Energy Plan for Commonwealth Edison; City of Chicago. Direct testimony, February 1 1994; rebuttal, September 1994.

Cost-effectiveness screening of demand-side management programs and measures; estimates by Commonwealth Edison of costs avoided by DSM and of future cost, capacity, and performance of supply resources.

117. **FERC** 2422 et al., Application of James River–New Hampshire Electric, Public Service of New Hampshire, for Licensing of Hydro Power; Conservation Law Foundation; 1993.

Cost-effective energy conservation available to the Public Service of New Hampshire; power-supply options; affidavit.

118. **Vermont PSB** 5270-CV-1,-3, and 5686; Central Vermont Public Service Fuel-Switching and DSM Program Design, on behalf of the Vermont Department of Public Service. Direct, April 1994; rebuttal, June 1994.

Avoided costs and screening of controlled water-heating measures; risk, rate impacts, participant costs, externalities, space- and water-heating load, benefit-cost tests.

119. **Florida PSC** 930548-EG–930551–EG, Conservation goals for Florida electric utilities; Legal Environmental Assistance Foundation, Inc. April 1994.

Integrated resource planning, avoided costs, rate impacts, analysis of conservation goals of Florida electric utilities.

120. **Vermont PSB** 5724, Central Vermont Public Service Corporation rate request; Vermont Department of Public Service. Joint surrebuttal testimony with John Plunkett. August 1994.

Costs avoided by DSM programs; Costs and benefits of deferring DSM programs.

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

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

122. **Michigan PSC** U-10554, Consumers Power Company DSM Program and Incentive; Michigan Conservation Clubs. November 1994.

Critique of proposed reductions in DSM programs; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

123. **Michigan PSC** U-10702, Detroit Edison Company Cost Recovery, on behalf of the Residential Ratepayers Consortium. December 1994.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

124. **New Jersey Board of Regulatory Commissioners** EM92030359, Environmental costs of proposed cogeneration; Freehold Cogeneration Associates. November 1994.

Comparison of potential externalities from the Freehold cogeneration project with that from three coal technologies; support for the study "The Externalities of Four Power Plants."

125. **Michigan PSC** U-10671, Detroit Edison Company DSM Programs; Michigan United Conservation Clubs. January 1995.

Critique of proposal to scale back DSM efforts in light of potential for competition. Loss of savings, increase of customer costs, and decrease of competitiveness. Discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

126. **Michigan PSC** U-10710, Power-supply-cost-recovery plan of Consumers Power Company; Residential Ratepayers Consortium. January 1995.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

127. **FERC** 2458 and 2572, Bowater–Great Northern Paper hydropower licensing; Conservation Law Foundation. February 1995.

Comments on draft environmental impact statement relating to new licenses for two hydropower projects in Maine. Applicant has not adequately considered how energy conservation can replace energy lost due to habitat-protection or -enhancement measures.

128. **North Carolina Utilities Commission** E-100, Sub 74, Duke Power and Carolina Power & Light avoided costs; Hydro-Electric–Power Producer's Group. February 1995.

     Critique and proposed revision of avoided costs offered to small hydro-power producers by Duke Power and Carolina Power and Light.

129. **New Orleans City Council** UD-92-2A and -2B, Least-cost IRP for New Orleans Public Service and Louisiana Power & Light; Alliance for Affordable Energy. Direct, February 1995; rebuttal, April 1995.

     Critique of proposal to scale back DSM efforts in light of potential competition.

130. **DCPSC** Formal 917, II, Prudence of DSM expenditures of Potomac Electric Power Company; Potomac Electric Power Company. Rebuttal testimony, February 1995.

     Prudence of utility DSM investment; prudence standards for DSM programs of the Potomac Electric Power Company.

131. **Ontario Energy Board** EBRO 490, DSM cost recovery and lost-revenue–adjustment mechanism for Consumers Gas Company; Green Energy Coalition. April 1995.

     DSM cost recovery. Lost-revenue–adjustment mechanism for Consumers Gas Company.

132. **New Orleans City Council** CD-85-1, New Orleans Public Service rate increase; Alliance for Affordable Energy. Rebuttal, May 1995.

     Allocation of costs and benefits to rate classes.

133. **MDPU** Docket DPU-95-40, Mass. Electric cost-allocation; Massachusetts Attorney General. June 1995.

     Allocation of costs to rate classes. Critique of cost-of-service study. Implications for industry restructuring.

134. **Maryland PSC** 8697, Baltimore Gas & Electric gas rate increase; Maryland Office of People's Counsel. July 1995

     Rate design, cost-of-service study, and revenue allocation.

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

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

136. **Arizona Commerce Commission** U-1933-95-317, Tucson Electric Power rate increase; Residential Utility Consumer Office. January 1996.

Review of proposed rate settlement. Used-and-usefulness of plant. Rate design. DSM potential.

137. **Ohio PUC** 95-203-EL-FOR; Campaign for an Energy-Efficient Ohio. February 1996

Long-term forecast of Cincinnati Gas and Electric Company, especially its DSM portfolio. Opportunities for further cost-effective DSM savings. Tests of cost effectiveness. Role of DSM in light of industry restructuring; alternatives to traditional utility DSM.

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

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

139. **Maryland PSC** 8720, Washington Gas Light DSM; Maryland Office of People's Counsel. May 1996.

Avoided costs of Washington Gas Light Company; integrated least-cost planning.

140. A. **MDPU** DPU 96-100; Massachusetts Utilities' Stranded Costs; Massachusetts Attorney General. Oral testimony in support of "estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities," July 1996.

Stranded costs. Calculation of loss or gain. Valuation of utility assets.

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

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

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

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

143. **Maryland PSC** 8725; Maryland Office of People's Counsel. July 1996.

Proposed merger of Baltimore Gas & Electric Company, Potomac Electric Power Company, and Constellation Energy. Cost allocation of merger benefits and rate reductions.

144. **New Hampshire PUC** DR 96-150, Public Service Company of New Hampshire stranded costs; New Hampshire Office of Consumer Advocate. December 1996.

Market price of capacity and energy; value of generation plant; restructuring gain and stranded investment; legal status of PSNH acquisition premium; interim stranded-cost charges.

145. **Ontario Energy Board** EBRO 495, LRAM and shared-savings incentive for DSM performance of Consumers Gas; Green Energy Coalition. March 1997.

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

146. **New York PSC** Case 96-E-0897, Consolidated Edison restructuring plan; City of New York. April 1997.

Electric-utility competition and restructuring; critique of proposed settlement of Consolidated Edison Company; stranded costs; market power; rates; market access.

147. **Vermont PSB** 5980, proposed statewide energy plan; Vermont Department of Public Service. Direct, August 1997; rebuttal, December 1997.

Justification for and estimation of statewide avoided costs; guidelines for distributed IRP.

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

Performance incentives proposed for the Boston Edison company.

149. **Vermont PSB** 5983, Green Mountain Power rate increase; Vermont Department of Public Service. Direct, October 1997; rebuttal, December 1997.

In three separate pieces of prefiled testimony, addressed the Green Mountain Power Corporation's (1) distributed-utility-planning efforts, (2) avoided costs, and (3) prudence of decisions relating to a power purchase from Hydro-Quebec.

150. **MDPU** 97-63, Boston Edison proposed reorganization; Utility Workers Union of America. October 1997.

Increased costs and risks to ratepayers and shareholders from proposed reorganization; risks of diversification; diversion of capital from regulated to unregulated affiliates; reduction in Commission authority.

151. **MDTE** 97-111, Commonwealth Energy proposed restructuring; Cape Cod Light Compact. Joint testimony with Jonathan Wallach, January 1998.

Critique of proposed restructuring plan filed to satisfy requirements of the electric-utility restructuring act of 1997. Failure of the plan to foster competition and promote the public interest.

152. **NH PUC** Docket DR 97-241, Connecticut Valley Electric fuel and purchased-power adjustments; City of Claremont, N.H. February 1998.

Prudence of continued power purchase from affiliate; market cost of power; prudence disallowances and cost-of-service ratemaking.

153. **Maryland PSC** 8774; APS-DQE merger; Maryland Office of People's Counsel. February 1998.

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

154. **Vermont PSB** 6018, Central Vermont Public Service Co. rate increase; Vermont Department of Public Service. February 1998.

Prudence of decisions relating to a power purchase from Hydro-Quebec. Reasonableness of avoided-cost estimates. Quality of DU planning.

155. **Maine PUC** 97-580, Central Maine Power restructuring and rates; Maine Office of Public Advocate. May 1998; Surrebuttal, August 1998.

Determination of stranded costs; gains from sales of fossil, hydro, and biomass plant; treatment of deferred taxes; incentives for stranded-cost mitigation; rate design.

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

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

157. **Vermont PSB** 6107, Green Mountain Power rate increase, Vermont Department of Public Service. Direct, September 1998; Surrebuttal drafted but not filed, November 2000.

Prudence of decisions relating to a power purchase from Hydro-Quebec. Least-cost planning and prudence. Quality of DU planning.

158. **MDTE** 97-120, Western Massachusetts Electric Company proposed restructuring; Massachusetts Attorney General. Joint testimony with Jonathan Wallach, October 1998. Joint surrebuttal with Jonathan Wallach, January 1999.

Market value of the three Millstone nuclear units under varying assumptions of plant performance and market prices. Independent forecast of wholesale market prices. Value of Pilgrim and TMI-1 asset sales.

159. **Maryland PSC** 8794 and 8804; BG&E restructuring and rates; Maryland Office of People's Counsel. Direct, December 1998; rebuttal, March 1999.

Implementation of restructuring. Valuation of generation assets from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

160. **Maryland PSC** 8795; Delmarva Power & Light restructuring and rates; Maryland Office of People's Counsel. December 1998.

Implementation of restructuring. Valuation of generation assets and purchases from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

161. **Maryland PSC** 8797; Potomac Edison Company restructuring and rates; Maryland Office of People's Counsel. Direct, January 1999; rebuttal, March 1999.

Implementation of restructuring. Valuation of generation assets and purchases from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

162. **Connecticut DPUC** 99-02-05; Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

Projections of market price. Valuation of purchase agreements and nuclear and non-nuclear assets from comparable-sales and cash-flow analyses.

163. **Connecticut DPUC** 99-03-04; United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

Projections of market price. Valuation of purchase agreements and nuclear assets from comparable-sales and cash-flow analyses.

164. **Washington UTC** UE-981627; PacifiCorp–Scottish Power Merger, Office of the Attorney General. June 1999.

Review of proposed performance standards and valuation of performance. Review of proposed low-income assistance.

165. **Utah PSC** 98-2035-04; PacifiCorp–Scottish Power Merger, Utah Committee of Consumer Services. June 1999.

Review of proposed performance standards and valuation of performance.

166. **Connecticut DPUC** 99-03-35; United Illuminating Company proposed standard offer; Connecticut Office of Consumer Counsel. July 1999.

Design of standard offer by rate class. Design of price adjustments to preserve rate decrease. Market valuations of nuclear plants. Short-term stranded cost

167. **Connecticut DPUC** 99-03-36; Connecticut Light and Power Company proposed standard offer; Connecticut Office of Consumer Counsel. Direct, July 1999; Supplemental, July 1999.

Design of standard offer by rate class. Design of price adjustments to preserve rate decrease. Market valuations of nuclear plants. Short-term stranded cost.

168. **W. Virginia PSC** 98-0452-E-GI; electric-industry restructuring, West Virginia Consumer Advocate. July 1999.

Market value of generating assets of, and restructuring gain for, Potomac Edison, Monongahela Power, and Appalachian Power. Comparable-sales and cash-flow analyses.

169. **Ontario Energy Board** RP-1999-0034; Ontario Performance-Based Rates; Green Energy Coalition. September 1999.

Rate design. Recovery of demand-side-management costs under PBR. Incremental costs.

170. **Connecticut DPUC** 99-08-01; standards for utility restructuring; Connecticut Office of Consumer Counsel. Direct, November 1999; Supplemental January 2000.

Appropriate role of regulation. T&D reliability and service quality. Performance standards and customer guarantees. Assessing generation adequacy in a competitive market.

171. **Connecticut Superior Court** CV 99-049-7239; Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. Affidavit, December 1999.

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

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

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

173. **Ontario Energy Board** RP-1999-0044; Ontario Hydro transmission-cost allocation and rate design; Green Energy Coalition. January 2000.

Cost allocation and rate design. Net vs. gross load billing. Export and wheeling-through transactions. Environmental implications of utility proposals.

174. **Utah PSC** 99-2035-03; PacifiCorp Sale of Centralia plant, mine, and related facilities; Utah Committee of Consumer Services. January 2000.

Prudence of sale and management of auction. Benefits to ratepayers. Allocation and rate treatment of gain.

175. **Connecticut DPUC** 99-09-12; Nuclear Divestiture by Connecticut Light & Power and United Illuminating; Connecticut Office of Consumer Counsel. January 2000.

Market for nuclear assets. Optimal structure of auctions. Value of minority rights. Timing of divestiture.

176. **Ontario Energy Board** RP-1999-0017; Union Gas PBR proposal; Green Energy Coalition. March 2000.

Lost-revenue-adjustment and shared-savings incentive mechanisms for Union Gas DSM programs. Standards for review of targets and achievements, computation of lost revenues. Need for DSM expenditure true-up mechanism.

177. **NY PSC** 99-S-1621; Consolidated Edison steam rates; City of New York. April 2000.

Allocation of costs of former cogeneration plants, and of net proceeds of asset sale. Economic justification for steam-supply plans. Depreciation rates. Weather normalization and other rate adjustments.

178. **Maine PUC** 99-666; Central Maine Power alternative rate plan; Maine Public Advocate. Direct, May 2000; Surrebuttal, August 2000.

Likely merger savings. Savings and rate reductions from recent mergers. Implications for rates.

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

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

180. **Connecticut DPUC** 99-09-03; Connecticut Natural Gas Corporation Merger and Rate Plan; Connecticut office of Consumer Counsel. September 2000.

Performance-based ratemaking in light of mergers. Allocation of savings from merger. Earnings-sharing mechanism.

181. **Connecticut DPUC** 99-09-12RE01; Proposed Millstone Sale; Connecticut Office of Consumer Counsel. November 2000.

Requirements for review of auction of generation assets. Allocation of proceeds between units.

182. **MDTE** 01-25; Purchase of Streetlights from Commonwealth Electric; Cape Light Compact. January 2001

Municipal purchase of streetlights; Calculation of purchase price under state law; Determination of accumulated depreciation by asset.

183. **Connecticut DPUC** 00-12-01 and 99-09-12RE03; Connecticut Light & Power rate design and standard offer; Connecticut Office of Consumer Counsel. March 2001.

Rate design and standard offer under restructuring law; Future rate impacts; Transition to restructured regime; Comparison of Connecticut and California restructuring challenges.

184. **Vermont PSB** 6460 & 6120; Central Vermont Public Service rates; Vermont Department of Public Service. Direct, March 2001; Surrebuttal, April 2001.

Review of decision in early 1990s to commit to long-term uneconomic purchase from Hydro Québec. Calculation of present damages from imprudence.

185. **New Jersey BPU** EM00020106; Atlantic City Electric Company sale of fossil plants; New Jersey Ratepayer Advocate. Affidavit, May 2001.

Comparison of power-supply contracts. Comparison of plant costs to replacement power cost. Allocation of sales proceeds between subsidiaries.

186. **New Jersey BPU** GM00080564; Public Service Electric and Gas transfer of gas supply contracts; New Jersey Ratepayer Advocate. Direct, May 2001.

Transfer of gas transportation contracts to unregulated affiliate. Potential for market power in wholesale gas supply and electric generation. Importance of reliable gas supply. Valuation of contracts. Effect of proposed requirements contract on rates. Regulation and design of standard-offer service.

187. **Connecticut DPUC** 99-04-18 Phase 3, 99-09-03 Phase 2; Southern Connecticut Natural Gas and Connecticut Natural Gas rates and charges; Connecticut Office of Consumer Counsel. Direct, June 2001; Supplemental, July 2001.

Identifying, quantifying, and allocating merger-related gas-supply savings between ratepayers and shareholders. Establishing baselines. Allocations between affiliates. Unaccounted-for gas.

188. **New Jersey BPU** EX01050303; New Jersey electric companies' procurement of basic supply; New Jersey Ratepayer Advocate. August 2001.

    Review of proposed statewide auction for purchase of power requirements. Market power. Risks to ratepayers of proposed auction.

189. **NY PSC** 00-E-1208; Consolidated Edison rates; City of New York. October 2001.

    Geographic allocation of stranded costs. Locational and postage-stamp rates. Causation of stranded costs. Relationship between market prices for power and stranded costs.

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

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

191. **New Jersey BPU** EM00020106; Atlantic City Electric proposed sale of fossil plants; New Jersey Ratepayer Advocate. December 2001.

    Current market value of generating plants vs. proposed purchase price.

192. **Vermont PSB** 6545; Vermont Yankee proposed sale; Vermont Department of Public Service. Direct, January 2002.

    Comparison of sales price to other nuclear sales. Evaluation of auction design and implementation. Review of auction manager's valuation of bids.

193. **Connecticut Siting Council** 217; Connecticut Light & Power proposed transmission line from Plumtree to Norwalk; Connecticut Office of Consumer Counsel. March 2002.

    Nature of transmission problems. Potential for conservation and distributed resources to defer, reduce or avoid transmission investment. CL&P transmission planning process. Joint testimony with John Plunkett.

194. **Vermont PSB** 6596; Citizens Utilities Rates; Vermont Department of Public Service. Direct, March 2002; Rebuttal, May 2002.

    Review of 1991 decision to commit to long-term uneconomic purchase from Hydro Québec. Alternatives; role of transmission constraints. Calculation of present damages from imprudence.

195. **Connecticut DPUC** 01-10-10; United Illuminating rate plan; Connecticut Office of Consumer Counsel. April 2002

Allocation of excess earnings between shareholders and ratepayers. Asymmetry in treatment of over- and under-earning. Accelerated amortization of stranded costs. Effects of power-supply developments on ratepayer risks. Effect of proposed rate plan on utility risks and required return.

196. **Connecticut DPUC** 01-12-13RE01; Seabrook proposed sale; Connecticut Office of Consumer Counsel. July 2002

Comparison of sales price to other nuclear sales. Evaluation of auction design and implementation. Assessment of valuation of purchased-power contracts.

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

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

198. **New Jersey BPU** ER02080507; Jersey Central Power & Light rates; N.J. Division of the Ratepayer Advocate. Phase I December 2002; Phase II (oral) July 2003.

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

199. **Connecticut DPUC** 03-07-02; CL&P rates; AARP. October 2003

Proposed distribution investments, including prudence of prior management of distribution system and utility's failure to make investments previously funded in rates. Cost controls. Application of rate cap. Legislative intent.

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

Application of rate cap. Legislative intent.

201. **Vermont PSB** 6596; Vermont Electric Power Company and Green Mountain Power Northwest Reliability transmission plan; Conservation Law Foundation. December 2003.

Inadequacies of proposed transmission plan. Failure of to perform least-cost planning. Distributed resources.

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

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

203. **NY PSC** Cases 03-G-1671 & 03-S-1672; Consolidated Edison Company Steam and Gas Rates; City of New York. Direct March 2004; Rebuttal April 2004; Settlement June 2004.

Prudence and cost allocation for the East River Repowering Project. Gas and steam energy conservation. Opportunities for cogeneration at existing steam plants.

204. **NY PSC** 04-E-0572; Consolidated Edison rates and performance; City of New York. Direct, September 2004; rebuttal, October 2004.

Consolidated Edison's role in promoting adequate supply and demand resources. Integrated resource and T&D planning. Performance-based ratemaking and streetlighting.

205. **Ontario EB** RP 2004-0188; cost recovery and DSM for Ontario electric-distribution utilities; Green Energy Coalition. Exhibit, December 2004.

Differences in ratemaking requirements for customer-side conservation and demand management versus utility-side efficiency improvements. Recovery of lost revenues or incentives. Reconciliation mechanism.

206. **MDTE** 04-65; Cambridge Electric Light Co. streetlighting; City of Cambridge. Direct, October 2004; Supplemental January 2005.

Calculation of purchase price of street lights by the City of Cambridge.

207. **NY PSC** 04-W-1221; rates, rules, charges, and regulations of United Water New Rochelle; Town of Eastchester and City of New Rochelle. Direct, February 2005.

Size and financing of proposed interconnection. Rate design. Water-mains replacement and related cost recovery. Lost and unaccounted-for water.

208. **NY PSC** 05-M-0090; system-benefits charge; City of New York. Comments, March 2005.

Assessment and scope of, and potential for, New York system-benefits charges.

209. **Maryland PSC** 9036; Baltimore Gas & Electric rates; Maryland Office of People's Counsel. Direct, August 2005.

Allocation of costs. Design of rates. Interruptible and firm rates.

210. **British Columbia Utilities Commission** Project No. 3698388, British Columbia Hydro resource-acquisition plan; British Columbia Sustainable Energy Association and Sierra Club of Canada BC Chapter. Direct, September 2005.

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

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

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

212. **Connecticut DPUC** 03-07-01RE03 & 03-07-15RE02; incentives for power procurement; Connecticut Office of Consumer Counsel. Direct, September 2005. Additional Testimony, April 2006.

Utility obligations for generation procurement. Application of standards for utility incentives. Identification and quantification of effects of timing, load characteristics, and product definition.

213. **Connecticut DPUC** Docket 05-10-03; Connecticut L&P; time-of-use, interruptible and seasonal rates; Connecticut Office of Consumer Counsel. Direct and Supplemental Testimony February 2006.

Seasonal and time-of-use differentiation of generation, congestion, transmission and distribution costs; fixed and variable peak-period timing; identification of pricing seasons and seasonal peak periods; cost-effectiveness of time-of-use rates.

214. **Ontario Energy Board** Case EB-2005-0520; Union Gas rates; School Energy Coalition. Evidence, April 2006.

Rate design related to splitting commercial rate class into two classes: new break point, cost allocation, customer charges, commodity rate blocks.

215. **Ontario Energy Board** Case EB-2006-0021; natural gas demand-side-management generic issues proceeding; School Energy Coalition. Evidence, June 2006.

Multi-year planning and budgeting; lost-revenue adjustment mechanism; determining savings for incentives; oversight; program screening.

216. **Indiana Utility Regulatory Commission** Cause Nos. 42943 and 43046; Vectren Energy DSM proceedings; Citizens Action Coalition. Direct, June 2006.

Rate decoupling and energy-efficiency goals.

217. **Pennsylvania PUC** Docket No. 00061346; Duquesne Lighting; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

Real-time and time-dependent pricing; benefits of time-dependent pricing; appropriate metering technology; real-time rate design and customer information

218. **Pennsylvania PUC** Docket No. R-00061366, et al.; rate-transition-plan proceedings of Metropolitan Edison and Pennsylvania Electric; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

Real-time and time-dependent pricing; appropriate metering technology; real-time rate design and customer information.

219. **Connecticut DPUC** 06-01-08; Connecticut L&P procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings September and October 2006.

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

220. **Connecticut DPUC** 06-01-08; United Illuminating procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings August and November 2006; March, September, October, and November 2007; February, April, and May 2008.

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

221. **NY PSC** Case No. 06-M-1017; policies, practices, and procedures for utility commodity supply service; City of New York. Comments, November and December 2006.

Multi-year contracts, long-term planning, new resources, procurement by utilities and other entities, cost recovery.

222. **Connecticut DPUC** 06-01-08; procurement of power for standard service and last-resort service, lessons learned; Connecticut Office Of Consumer Counsel. Comments and Technical Conferences December 2006 and January 2007.

Sharing of data and sources; benchmark prices; need for predictability, transparency and adequate review; utility-owned resources; long-term firm contracts.

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

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

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

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

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

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

226. **Connecticut DPUC** Docket 07-04-24, Review of capacity contracts under Energy Independence Act; Connecticut Office of Consumer Counsel, Joint Direct Testimony June 2007.

Assessment of proposed capacity contracts for new combined-cycle, peakers and DSM. Evaluation of contracts for differences, modeling of energy, capacity and forward-reserve markets. Corrections of errors in computation of costs, valuation of energy-price effects of peakers, market-driven expansion plans and retirements, market response to contracted resource additions, DSM proposal evaluation.

227. **NY PSC** Case 07-E-0524, Consolidated Edison electric rates; City of New York. Direct, September 2007.

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

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

Revenue allocation, rate design, and demand-side management. Estimation of marginal costs and export revenues.

229. **Mass. EFSB** 07-7, DPU 07-58 & -59, proposed Brockton Power Company plant; Alliance Against Power Plant Location. Direct, March 2008

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

230. **CDPUC 08-01-01**, peaking generation projects; Connecticut Office of Consumer Counsel. Direct (with Jonathan Wallach), April 2008.

Assessment of proposed peaking projects. Valuation of peaking capacity. Modeling of energy margin, forward reserves, other project benefits.

231. **Ontario EB-2007-0905,** Ontario Power Generation payments; Green Energy Coalition. Direct, April 2008.

Cost of capital for Hydro and nuclear investments. Financial risks of nuclear power.

232. **Utah PSC 07-035-93,** Rocky Mountain Power Rates; Utah Committee of Consumer Services. Direct, July 2008

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

233. **Ontario EB-2007-0707,** Ontario Power Authority integrated system plan; Green Energy Coalition, Penimba Institute, and Ontario Sustainable Energy Association. Evidence (with Jonathan Wallach and Richard Mazzini), August 2008.

Critique of integrated system plan. Resource cost and characteristics; finance cost. Development of least-cost green-energy portfolio.

234. **NY PSC** Case 08-E-0596, Consolidated Edison electric rates; City of New York. Direct, September 2008.

Estimated bills, automated meter reading, and advanced metering. Aggregation of building data. Targeted DSM program design. Using distributed generation to defer T&D investments.

235. **CDPUC 08-07-01**, integrated resource plan; Connecticut Office of Consumer Counsel. Direct, September 2008.

Integrated resource planning scope and purpose. Review of modeling and assumptions. Review of energy efficiency, peakers, demand response, nuclear, and renewables. Structuring of procurement contracts.

236. **Manitoba PUB** 2008 MH EIIR, Manitoba Hydro intensive industrial rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. Direct, November 2008.

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

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

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

238. **Vermont PSB** 7440; extension of authority to operate Vermont Yankee; Conservation Law Foundation and Vermont Public Interest Research Group. Direct, February 2009; Surrebuttal, May 2009.

Adequacy of decommissioning funding. Potential benefits to Vermont of revenue-sharing provision. Risks to Vermont of underfunding decommissioning fund.

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

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

240 **Nova Scotia Review Board** P-172, proposed biomass project, Nova Scotia Consumer Advocate. June 2009.

Procedural, planning, and risk issues with proposed power-purchase contract. Biomass price index. Nova Scotia Power's management of other renewable contracts.

241. **Connecticut Siting Council** 370A, Connecticut Light & Power transmission projects; Connecticut Office of Consumer Counsel. Direct, July 2009.

Need for transmission projects. Modeling of transmission system. Realistic modeling of operator responses to contingencies

242 **Mass. DPU** 09-39, NGrid rates, Mass. Department of Energy Resources. August 2009.

Revenue-decoupling mechanism. Automatic rate adjustments.

243 **Utah PSC** Docket No. 09-035-23, Rocky Mountain Power rates, Utah Office of Consumer Services. October 2009.

Cost-of-service study. Cost allocators for generation, transmission, and substation.

Forecast of Philadelphia Gas Works Avoided Gas Costs

By Paul Chernick

The economic evaluation of an energy-efficiency measure requires an estimate of the measure's benefits. The major benefit of gas energy-efficiency programs is the reduction of gas use and associated costs to customers. Those avoided costs may be passed on to customers by the utility, third-party suppliers, or both, but they are all eventually paid by customers.

Electric avoided costs are often computed for a number of cost drivers, such as summer and winter contribution to system peak load, and on seasonal energy use for on- and off-peak periods. In the cost-benefit computation, analysts estimate the effect of a proposed measure or program on each of the cost drivers. The benefit of the energy-efficiency proposal is then estimated by multiplying the energy savings for each cost driver by the per-unit avoided cost for that driver, and adding up the benefits for all the drivers. This approach works well for evaluation of electric energy-efficiency programs, simplifying the costs of serving loads for 8,760 hours to a few cost drivers, which can be estimated for the wide variety of electric end uses (e.g., residential and commercial space heating, space cooling, ventilation, water heating, refrigeration, indoor and outdoor lighting, clothes drying, cooking, computers and other plug loads, as well as a range of industrial loads).

Like most detailed analyses of avoided gas costs, this study's calculation of avoided costs is structured differently than that usually used to estimate electric avoided costs. Planning and procurement for natural gas is primarily concerned with daily loads, rather than annual loads, so there are fewer load shapes. There are also fewer end uses for gas than electricity, since very little gas is used for lighting, refrigeration, or residential air conditioning, and no gas is used for computers or ventilation. Hence, it is feasible to compute avoided costs for the load shapes of the few gas end uses. In the cost-benefit analysis, the benefit of each energy-efficiency measure can be estimated as the measure's annual savings times a single load-specific avoided cost.

This load-shape approach to defining avoided costs allows for distinctions between the costs of different end uses that impose different costs, even for similar seasonal usage levels. An end use that does not vary with weather, such as cooking or clothes drying, may use the same amount of gas in the winter as a heating boiler, but the gas to serve the boiler will be more expensive. The boiler will predictably use more gas on very cold days, when gas is most expensive, and less on mild days, when gas is relatively cheap. Serving the boiler requires the reservation of enough pipeline capacity to meet load on typical cold days, and the construction of local transmission-and-distribution capacity and supplemental gas supplied to meet load on extraordinarily cold days. The boiler will use more gas on cold days, when regional gas demand is high and prices are high. The development of avoided cost by load shape allows for the reflection of these differences between loads even within a season or a month.

This estimate of avoided gas costs comprises the following three parts:

- *Commodity:* The market prices of gas delivered to a utility's citygate in a normal year
- *Peaking capacity:* The costs of local capacity to cover the difference between normal and design-peak conditions
- *Local transmission and distribution* (T&D): The utility's cost of building, operating and maintaining the high-pressure transmission and lower-pressure distribution system in its service area

Commodity Cost

I forecast the monthly delivered gas price to the PGW citygate for gas delivered evenly over the month, as the sum of the price of gas delivered to the Henry Hub and the price basis (the price different) from Henry Hub to Zone M3 of the Texas Eastern Transmission (TETCo) pipeline, which includes the PGW citygate.

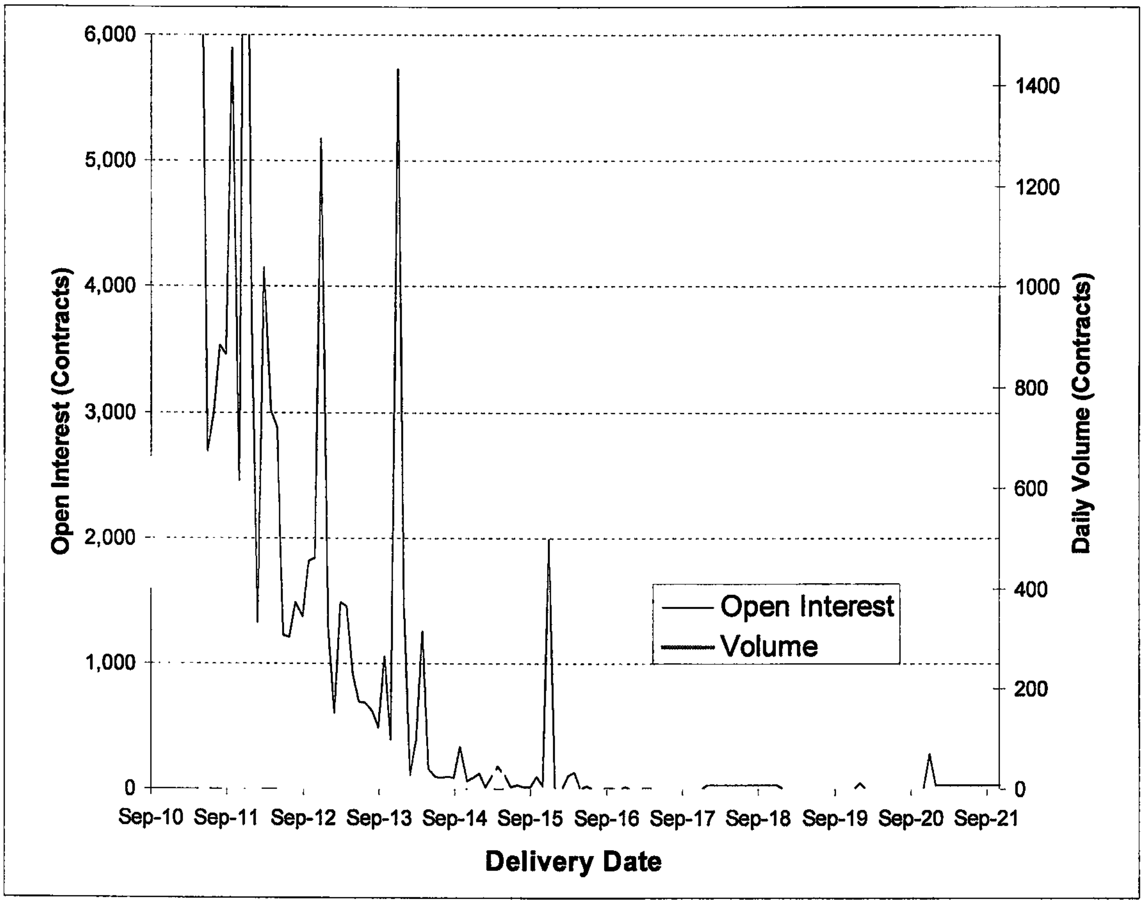
For the period from September 2010 through August 2014, I computed the monthly prices as the sum of the NYMEX forward price for Henry Hub (NYMEX contract NG) and the TETCo basis forward (NYMEX contract NX). Since NYMEX reports TETCo forwards only through July 2013, I assumed that the basis would remain at the April–July 2013 value through October 2013,[1] and that the basis in each subsequent month would be equal to the basis in the same month one year earlier, in real terms.

After 2014, the trading of NYMEX Henry Hub futures becomes quite thin. On September 28, 2009, for example, 115,000 Henry Hub contracts (of 10 billion Btu each) were outstanding for the 2010/11 gas year, but only about 1,200 contracts

[1]The TETCo basis forwards in each year 2010 through 2012 are equal throughout the April–October period.

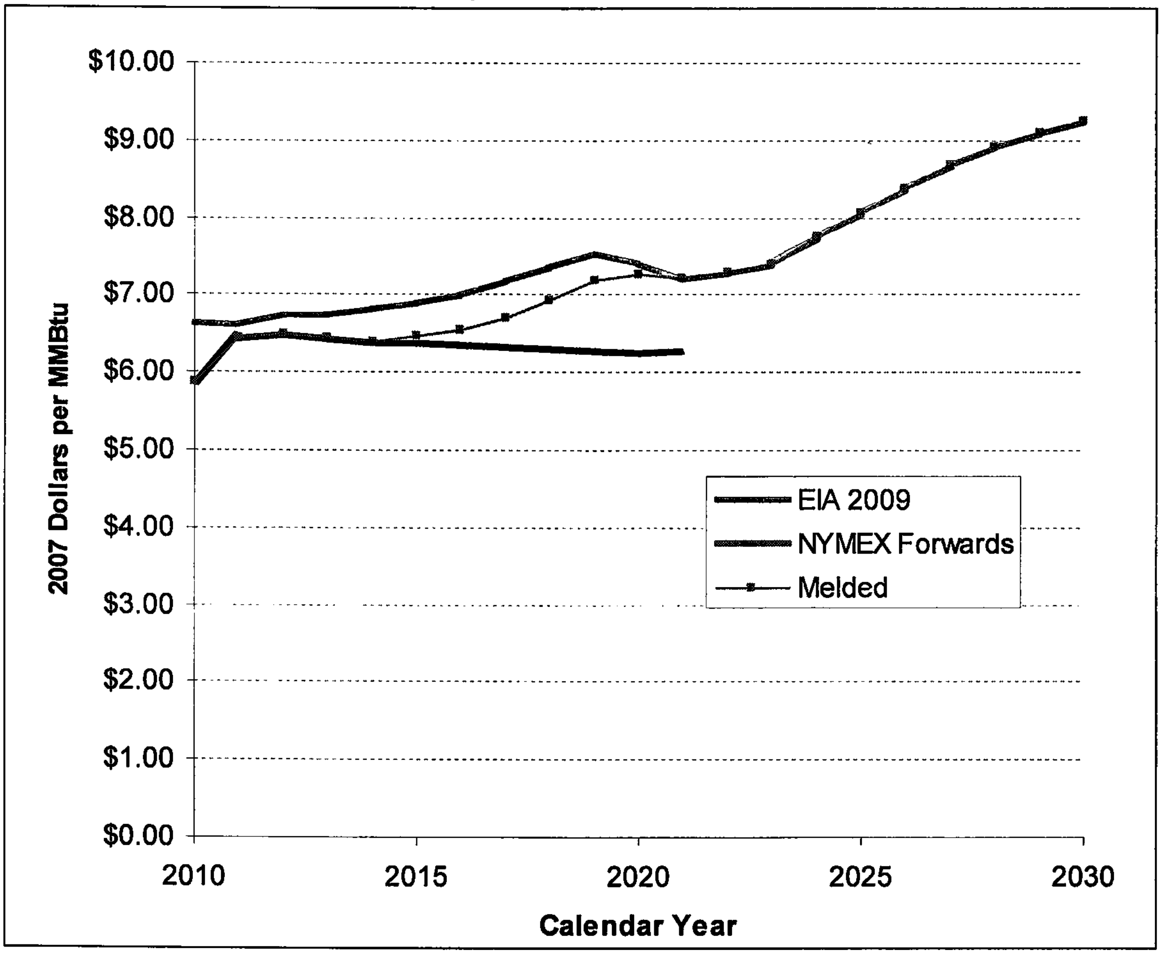
for 2014/15. On many days, no contracts are traded for most months beyond 2010/11. See Figure 2-1.

Figure 2-1: NYMEX Henry Hub (NG) Forward Market, September 28, 20091



Given the thin trading in the Henry Hub contract starting in 2014, I do not have much faith that the NYMEX prices are meaningful in the later years. I therefore put increasing weight on the forecast of Henry Hub prices in the 2009 Annual Energy Outlook published by the Energy Information Administration (EIA 2009, 32, Table A13). From gas years 2014/15 through 2021/22, I trend my projection of the Henry Hub gas price from 100% reliance on the NYMEX forwards to 100% reliance on EIA. After 2011/22, I use EIA's gas-price projection. See Figure 2-2.

Figure 2-2: Projections of Henry Hub Gas Prices



From these forwards, I computed annual commodity costs for the following three load shapes:

- *baseload,* including industrial processes, cooking, and clothes drying, modeled as using the same amount of gas every day.
- *space heating,* modeled as using gas each day in proportion to daily heating degree days (HDD).
- *water heating,* modeled as a mix of baseload and space-heating load. This approximation reflects the observation that gas usage by water-heating customers rises in the winter months, probably as a combination of higher standby losses and warmer water temperatures for baths, showers, and washing.

While gas utilities do not purchase a large portion of their supply in the daily spot market, the short-term market—where utilities can procure gas to meet higher-than-expected load, or sell off gas when their supplies exceed their needs—determines the value of the gas. Every dekatherm of gas that a PGW consumer does not use is one more dekatherm available to someone in the spot market who is willing to pay the spot price for that gas. Depending on the gas-supply situation and contracts of the utility (or gas supplier), the utility may avoid buying gas from the spot market, or sell more gas into the spot market, or reduce its use of some longer-term contract.

In the longer term, annual and multi-year contracts should average near the spot prices for the same time periods. Estimating the effect of specific load reductions on the supply portfolio and costs of any particular utility or gas supplier is complicated, since the calculation would entail modeling purchases, sales and usage of a variety of gas supplies, pipeline capacity, storage resources, and supplementary resources. This approach would also require non-public data from competitive gas suppliers. The spot-market price is a reasonable estimate of the resource benefit from reduced commodity use.

Baseload Commodity

For baseload end uses, where use of gas does not vary with weather or the season, the analysis weights the forecast monthly gas price by the number of days in the month.

Space-Heating Commodity

The cost of commodity for space heating varies from the cost of baseload in two ways. First, the amount of gas used varies among months, and is concentrated in the higher-cost winter months. Second, within each month, space heating uses more gas on the colder days, when gas tends to be more expensive than the average for the month.

For the first factor, the monthly percentage the study assumed that the monthly use of gas for space heating is proportional to the monthly sum of daily heating degree days (HDDs). Heating degree days are the difference between the day's average temperature and a base temperature, at which space-heating use is assumed to be zero. That base temperature, or balance point, is lower than the temperature maintained by the thermostat, since the building is warmed by sun shining in the windows and by interior gains (waste heat) from lights, appliances, equipment, and people.

I used the monthly average HDDs with a base of 65° F for 1978–2007 published by NOAA (2007).

The second factor, the effect of the intra-month correlation of price and load, reflects the fact that heating loads use more gas on colder days within each month, and that prices tend to be higher on cold days.[2] This correction was computed as the typical ratio of the heating-load-weighted market price to the average daily price for the month. Since the NYMEX prices are for gas delivered evenly over the month, multiplying that ratio by the NYMEX-based price forecast results in an estimate of the price of gas for heating load in the month.

Of course, gas prices vary due to factors other than the current day's temperature in Philadelphia, including the following:

- wind and sunshine on that day, since heating load will be greater on a cloudy, windy 40°F day than a sunny calm day with the same air temperature.
- weather in other parts of North America. A cold snap in California will drive up wellhead prices in Texas and Alberta, and hence prices for deliveries to Pennsylvania. Cold temperatures in New England or New York raise not only wellhead prices but also market prices for delivery to New York citygates. Conversely, mild weather elsewhere can moderate prices in Philadelphia, even when it is cold in Philadelphia.
- weather on other days. High gas demand in earlier days of the same month, or in earlier months, will tend to deplete storage and push prices higher. Forecasts of cold weather in coming days and weeks will tend to push up price before the cold front hits, as users scramble to put gas into storage.
- The amount of gas in storage, which depends on the weather, other gas demands over the previous year or so, market participants' guesses regarding price tends, and other factors.
- demand for gas for electric generation, which varies during the month with oil prices and outages of coal and nuclear plants and between years as load grows and supplies change.
- gas-production capacity, which changes within winter months primarily due to freeze-ups of gas wells in producing areas, but changes significantly between years due to depletion and new additions (and sometimes hurricanes).

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[2]The utility or a gas supplier can meet load in those high-load high-priced days with spot purchases, by reserving storage and associated transportation to the citygate, or by reserving additional pipeline capacity directly to the citygate. All these approaches impose costs that would not be needed for a load that was constant across the days of the month.

For this study, the intra-month price ratio was computed for each calendar month using data for each of the last two gas years, 2006/07 and 2007/08. The analysis computes the ratio of load-weighted to average monthly price for each month.

Equation 1. Intra-Month Heating Price Ratio.

$$\text{intra-month heating price ratio} = \frac{\left[\dfrac{\sum_{month} HD_{day} \times P_{day}}{\sum_{month} HD_{day}}\right]}{\left[\dfrac{\sum_{month} P_{day}}{\text{\# days in the month}}\right]}$$

where HD_{da} = heating degree-days for the day
P_{day} = delivered price for the day

The ratios tend to be highest in the winter and close to 1.00 in the shoulder months.

The heating commodity cost for each year is the sum across months of the following product:

NYMEX monthly forward × monthly HDD % × intra-month price ratio

The annual heating commodity cost is significantly greater than the annual baseload commodity cost. The annual residential heating avoided cost, averaged over the period 2006–2025, is about 17% greater than average annual baseload price. These differences can largely be explained by the fact that most of the heating usage is in the high-priced months of January, February, and December.

Water-Heating Commodity

My previous experience indicates that water-heating load is largely equal across months and days, but rises somewhat in colder weather. The observed load shape is probably attributable to a combination of higher standby losses and increased usage (for longer, hotter showers and baths, and warmer water for hand-washing) in cold weather. I assumed that the avoided water-heating commodity cost equals a 75% weighting of the baseload avoided cost and 25% weighting of space-heating avoided cost.

Commodity-Cost Summary

Figure 2-3 shows avoided commodity costs for the three load shapes. The relationships among the prices for the various load shapes are as expected. The heating cost is higher than the water-heating cost, which is higher than the baseload cost.

The average costs of utility gas supplies, which serve large amounts of heating load, tend to be much higher than the flat year-round gas supplies reflected in the baseload commodity costs. The average avoided commodity cost will similarly be more expensive than the avoided commodity cost for a flat year-round gas supply.

Peaking-Capacity Cost

In addition to buying and delivering the gas required in a normal year, a gas utility must be prepared to meet much higher loads on an extremely cold (design) day, through a cold snap, or in a very cold winter season. The prices for gas in a normal year do not include the costs of reserving capacity and supplies to meet design conditions. Those design loads are normally met by local storage (such as liquefied natural gas) and/or peaking off-system storage and associated transportation. The commodity costs reflect the costs of normal weather, while the peaking supplies reflect the resources maintained to meet design weather.

For PGW, design conditions include both a design day with 65 HDD (last experienced on January 17, 1982) and a design winter with heating loads approximately 19.4% more than normal. I estimated the cost of reserves to meet those conditions as the price of PGW's contracts supporting its most expensive storage supply (Equitrans) times the percentage increase in heating load between normal and design winters. I took the fixed cost of the Equitrans supply as $2.40/Dth, from Schedule SDS-8 of PGW'S Supporting Documentation filed on June 2008. Exhibit PLC-3 shows my computation of normal heating sendout (42.5 million Dth) and the design-winter sendout increment (8.3 million Dth). 0.194 Dth of peaking supply at $2.40/Dth of peaking results in a peaking-reserve cost for heating load of about $0.50/Dth; see Figure 2-3.

Since baseload has no increment of sendout on the design peak over average conditions, it would not have any peaking capacity charges.

Avoided Transmission-and-Distribition Cost

As peak loads grow, local distribution companies need to expand their internal transmission and distribution systems by adding parallel mains, looping, and increasing operating pressures, and increasing the size of new and replacement lines. The expenditures vary across each utility's service area and over time. Most utilities will include some areas in which relatively small increments of load require expensive upgrades, along with other load areas with excess capacity for many years resulting in no expansion costs. Marginal or avoided T&D costs are therefore generally estimated by comparing growth-related costs to peak load growth over a period of several years.

Since PGW expects sales to continue to decline and does not expect sales growth in the vast majority of its service territory, the opportunities for load reductions to reduce T&D investments will be quite limited. I did not include any avoided T&D costs in these avoided-cost estimates.

Figure 2-3: Computation of Avoided Costs, Part 1

	Ratio of weather-adj to simple average	Percent of normal HDD	percent of days	Year Starting 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Sep	0.983	0.8%	8.2%	6.648	7.157	7.334	7.474	7.614	7.765	7.906	8.047	8.208	8.355	8.476	8.618
Oct	1.045	5.7%	8.5%	6.805	7.247	7.414	7.554	7.699	7.850	7.991	8.132	8.293	8.440	8.566	8.703
Nov	1.006	11.5%	8.2%	7.190	7.527	7.612	7.710	7.859	8.008	8.152	8.306	8.470	8.625	8.780	8.915
Dec	1.012	18.0%	8.5%	8.147	8.419	8.489	8.615	8.771	8.932	9.099	9.277	9.455	9.638	9.847	10.011
Jan	1.054	21.4%	8.5%	9.152	9.399	9.459	9.600	9.782	9.959	10.152	10.346	10.546	10.747	10.973	
Feb	1.027	18.0%	7.7%	9.075	9.337	9.399	9.534	9.714	9.891	10.082	10.275	10.474	10.673	10.893	
Mar	1.027	14.3%	8.5%	7.905	8.144	8.202	8.312	8.478	8.634	8.805	8.977	9.159	9.331	9.519	
Apr	1.009	7.6%	8.2%	6.947	7.134	7.274	7.379	7.535	7.666	7.832	7.993	8.135	8.281	8.443	
May	1.000	2.4%	8.5%	6.902	7.094	7.229	7.334	7.495	7.626	7.792	7.953	8.095	8.241	8.398	
Jun	1.000	0.3%	8.2%	6.972	7.164	7.299	7.419	7.575	7.706	7.872	8.033	8.175	8.316	8.468	
Jul	1.000	0.0%	8.5%	7.057	7.244	7.379	7.514	7.665	7.806	7.962	8.123	8.265	8.406	8.553	
Aug	1.000	0.0%	8.5%	7.127	7.304	7.444	7.584	7.735	7.876	8.022	8.183	8.330	8.456	8.603	
Simple average				7.487	7.757	7.871	7.996	8.153	8.303	8.465	8.63	8.793	8.951	9.119	
HDD-weighted average				8.396	8.674	8.756	8.883	9.054	9.220	9.398	9.579	9.764	9.948	10.148	

Figure 2-3 continues on the following page.

Figure 2-3 Continued: Computation of Avoided Costs, Part 2

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
EIA (2009) HH Real Escalation					0.4%	1.2%	2.0%	3.0%	3.8%	1.9%	−0.1%	0.4%	1.4%	3.8%	4.3%	3.8%	3.6%	3.0%	2.2%	1.9%	0.6%	2.2%			
Commodity Price Projection[a]																									
Simple average	7.487	7.757	7.871	7.996	8.188	8.441	8.764	9.183	9.685	10.049	10.238	10.483	10.824	11.419	12.096	12.761	13.440	14.083	14.652	15.196	15.584	16.210	16.534	16.864	17.202
HDD-weighted average	8.396	8.674	8.756	8.883	9.097	9.378	9.737	10.203	10.760	11.164	11.375	11.647	12.026	12.687	13.439	14.178	14.932	15.646	16.279	16.883	17.315	18.009	18.370	18.737	19.112
Avoided Peaking Cost																									
Heating[b]	0.516	0.526	0.536	0.547	0.558	0.569	0.581	0.592	0.604	0.616	0.628	0.641	0.654	0.667	0.68	0.694	0.708	0.722	0.736	0.751	0.766	0.781	0.797	0.813	0.829
Totals Nominal Dollars																									
Baseload	7.49	7.76	7.87	8.00	8.19	8.44	8.76	9.18	9.68	10.05	10.24	10.48	10.82	11.42	12.10	12.76	13.44	14.08	14.65	15.20	15.58	16.21	16.53	16.86	17.20
Space Heating	8.91	9.20	9.29	9.43	9.66	9.95	10.32	10.79	11.36	11.78	12.00	12.29	12.68	13.35	14.12	14.87	15.64	16.37	17.02	17.63	18.08	18.79	19.17	19.55	19.94
Water Heating	7.84	8.12	8.23	8.35	8.55	8.82	9.15	9.59	10.10	10.48	10.68	10.93	11.29	11.90	12.60	13.29	13.99	14.65	15.24	15.81	16.21	16.85	17.19	17.54	17.89
Totals 2008 Dollars																									
Baseload	7.20	7.31	7.27	7.24	7.27	7.35	7.48	7.68	7.94	8.08	8.07	8.10	8.20	8.48	8.81	9.11	9.41	9.67	9.86	10.03	10.08	10.28	10.28	10.28	10.28
Space Heating	8.57	8.67	8.58	8.54	8.57	8.66	8.81	9.03	9.32	9.47	9.46	9.50	9.61	9.92	10.29	10.62	10.95	11.24	11.45	11.63	11.70	11.92	11.92	11.92	11.92
Water Heating	7.54	7.65	7.60	7.57	7.60	7.68	7.81	8.02	8.29	8.43	8.42	8.45	8.55	8.84	9.18	9.49	9.80	10.06	10.26	10.43	10.48	10.69	10.69	10.69	10.69

[a] For 2010–2013, projection from NYMEX. For 2012–2034, 90% escalated at HH, plus general inflation.

[b] For each year, fixed storage cost per Dth × (incremental design Dth ÷ normal-weather heating Dth), computed as follows:

- Fixed storage costs at $2.40/Dth (from SDS-8);
- Design sendout at 0.194 incremental Dth per Dth of normal-weather heating load: Normal Heating Sendout of 42.5 MM Dth ÷ Design Heating Increment of 8.26 MM Dth. See Exhibit PLC-3.

Works Cited

EIA. 2009. "An Updated Annual Energy Outlook 2009 Reference Case Reflecting Provisions of the American Recovery and Reinvestment Act and Recent Changes in the Economic Outlook" SR-OIAF/2009-03. Washington: Energy Information Administration.

NOAA. 2007. "2007 Local Climatological Data: Annual Summary With Comparative Data, Philadelphia, Pennsylvania (KPHL)" ISSN 0198-4535. Washington: National Oceanographic and Atmospheric Administration.

Exhibit PLC-3: Peaking-Supply Requirement

	Total Volume	Interruptible Sales	Firm Sales & Transport *Total*	Firm Sales & Transport *Per Day*	Units	Source
Computation of Baseload						
Sep-08	1,150,924	30,262	1,120,662	37,355	Mcf sales	GCR-3
Jul-09	1,272,769	22,420	1,250,349	40,334	Mcf sales	GCR-3
Aug-09	1,225,968	22,479	1,203,489	38,822	Mcf sales	GCR-3
Average				38,837	Mcf sales	
Annual Baseload			14,175,562		Mcf sales	Summer daily average × 365
Total Annual Normal Sendout						
Total Firm	54,991,226	1,396,648	53,594,578		Mcf sales	GCR-3
Firm Heating			39,419,016		Mcf sales	Total - Baseload
			40,838,101		Dth sales	1.036
			42,495,423		Dth sendout	0.961
Incremental Requirement, Normal to Design						
Design	68,284,128				Dth sendout	SDS-4, p. 1
Normal	60,025,061				Dth sendout	SDS-4, p. 1
Increment	8,259,067				Dth sendout	

Schedules CGR-3 and SDS-4 are from Volume I of supporting documentation filed with the Philadelphia Gas Commission by PGW in June of 2008.