STATE OF NEW JERSEY

BEFORE THE BOARD OF PUBLIC UTILITIES

In the Matter of the Petition of	**)**	
Jersey Central Power and Light Company	**)**	**Docket No. ER02080507**
for Approval of an Increase in Base Tariff	**)**	
Rates, Deferred Balances Filing, 2002	**)**	
RAC Filing and 2002 CED Filing	**)**	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE RATEPAYER ADVOCATE

Resource Insight, Inc.

DECEMBER 20, 2002

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I. Identification and Qualifications

Q: State your name, occupation and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 347 Broadway, Cambridge, Massachusetts 02139.

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, power supply planning, rate design, cost allocation, and utility industry restructuring. My resume is appended to this testimony as Schedule PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified approximately one hundred and eighty times on utility issues before various regulatory, legislative, and judicial bodies, including the

New Jersey Board of Public Utilities, Massachusetts Department of Public Utilities, Massachusetts Energy Facilities Siting Council, Vermont Public Service Board, Maine Public Utilities Commission, Rhode Island Public Utilities Commission, Connecticut Department of Public Utility Control, Texas Public Utilities Commission, New Mexico Public Service Commission, District of Columbia Public Service Commission, Michigan Public Service Commission, Minnesota Public Utilities Commission, Public Utilities Commission of Ohio, South Carolina Public Service Commission, North Carolina Utilities Commission, Florida Public Service Commission, Pennsylvania Public Utilities Commission, New York Public Service Commission, Arizona Commerce Commission, New Orleans City Council, Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. My resume includes a detailed list of my previous testimony.

Q: In whish proceedings have you testified before this Board?

A: I have testified for the Ratepayer Advocate in

- Docket No. GM00080564, on the proposal by Public Service Electric and Gas ("Public Service") to transfer its gas contracts to an unregulated affiliate,
- Docket No. BPU EM00020106, on the valuation of power plants and the allocation of proceeds from Atlantic City Electric Company's ("Atlantic") fossil-plant sale, and
- Docket No. EX1050303, on the structure of the auction for fourth-year BGS supply.

Q: Have you worked on other utility-regulation projects in New Jersey?

A: Yes. I have assisted the Ratepayer Advocate in reviewing two rounds of Atlantic Electric's competitive procurement of energy and capacity to serve its BGS loads, and in negotiations related to the restructuring of the Public Service contracts for gas supply to, and electricity purchases from, the Camden, Bayonne and Eagle Point NUGs.

Q: Have you testified previously on the power-supply decisions of electric utilities?

A: Yes, in the following cases:

- Illinois Commerce Commission 82-0026 (nuclear plant)
- FERC ER81-749-000 and ER82-325-000 (Pilgrim 2 nuclear project)
- Mass. DPU (now DTE) 84-145 (Seabrook 2 nuclear project)
- Maine PUC 84-120 (Pilgrim 2)
- Maine PUC 84-113 (Seabook 2)
- Mass. DPU (now DTE) 85-270 (Millstone 3 nuclear project)
- Mass. DPU (now DTE) 89-100 (Pilgrim I)
- Vermont PSB 5491 (energy-supply options)
- Mass. DPU (now DTE) 94-49 (Comprehensive least-cost planning)
- Vermont PSB 5983 (Hydro-Québec power purchase)
- NH PUC DR 97-241 (Power purchases)
- Vermont PSB 6018 (Hydro-Québec power purchase)
- Utah PSC 99-2035-03 (Centralia plant and mine)
- Vermont PSB 6460 and 6120 (Hydro-Québec power purchase)
- Vermont PSB 6596 (Hydro-Québec power purchase)

II. Introduction and Summary

Q: On whose behalf are you testifying in this proceeding?

A: I am testifying on behalf of the Division of Ratepayer Advocate.

Q: What is the purpose of your testimony?

A: I discuss the request of Jersey Central Power and Light (the Company or JCP&L) for approval of the portion of its deferred balances that represent the difference between the costs JCP&L has booked for the power supply it obtained for basic generation service (BGS), and the revenues from the generation portion of the bills of customers taking BGS from the Company.[1] My review covers the first three years of competition, from August 1, 1999 through July 31, 2002. During this period JCP&L was responsible for making all the decisions regarding procurement of BGS supply.

Q: Please describe the history and context of JCP&L's BGS procurement.

A: The Company, along with its sister utilities in the GPU system, decided to divest its generation assets. For its largest asset sale, covering most of its fossil-fueled generation, JCP&L decided not to include a transitional PPA to replace the energy from the divested plants. As a result of these two decisions, JCP&L became very dependent on an untested and volatile market. In the first three years of competition, the Company purchased over $1.6 billion in bilateral transactions, interchange purchases and ancillary services, and spent another $100 million for financial instruments to moderate the risks from those market

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[1]In the earlier part of the BGS period JCP&L was a subsidiary of GPU Energy. Since November 2001 JCP&L has been a subsidiary of FirstEnergy. My references to JCP&L include GPU or FirstEnergy, as appropriate.

purchases. My review of the Company's BGS procurement focussed on those purchases.

Q: Please summarize your testimony.

A: In the next section, I discuss issues related to the cost of the Company's BGS supply. In Section IV, I describe the standards and expectations I applied in my review of the Company's procurement of BGS supply. In Section V, I describe the Company's documentation of its procurement process and procurement decisions and I evaluate the available information.

Q: Please summarize your conclusions.

A: The Company has not demonstrated that it exercised the level of care appropriate for a procurement process of the size of the BGS supply. The Company has not provided any comparison of its expenditures to any measure of market prices, a basic step in demonstrating that it performed well in this important task. The only cost comparison in this record demonstrates that JCP&L's BGS costs (excluding some fixed costs, such as NUGs and transitional PPAs) were about 13% higher than those of its affiliate utilities in Pennsylvania, where GPU had much stronger cost-control incentives. The difference costs between states was about $240 million in the first three years of competition, or most of the $290 million JCP&L deferred in that period.

The Company's failure to compare the services it purchased for BGS to other measures of the cost of those services raises questions about its commitment to controlling the cost of BGS. The same failure, coupled with JCP&L's failure to provide the data necessary for other parties to conduct such a review, limits the Board's ability to determine whether the costs of BGS supply turned out to be reasonable (which is a separate question from whether the Company's process was reasonable).

Considering that the Company was managing a $3 billion program over the first three years of competition, including $1.7 billion in market purchases, one would expect JCP&L to be very concerned about creating and maintaining a clear record of its policies, guidelines, and decisions, and about the outcomes of those decisions. Such a record would be essential to internal management, control, and review of BGS procurement policy, as well as for demonstrating the prudence of those policies to the Board. The Company did not present any such record in its testimony. Even on discovery was able to provide only a partial and inconsistent accounting of its actions, and took a surprisingly long time to provide what it did.

The Company's failure to document its decisions regarding BGS procurement makes it impossible for the Board to find that JCP&L was prudent in selecting objectives, establishing techniques and procedures for implementing those objectives, and executing the actions selected in the planning process. The lack of retrospective reports and analyses of JCP&L's decisions also directly raises questions about prudence, since frequent reports would be necessary to evaluate performance in this novel environment.

The descriptions of JCP&L's procurement process in the direct testimony of Messrs. Stathis and Mascari primarily concern on-peak energy procurement, although that is not always clear in the testimony. Those descriptions are vague and sometimes misleading.

On discovery, the Company has not clarified the basis for its procurement decisions. To the contrary, the limited data that JCP&L provided on discovery are inconsistent with the assertions made in the testimony. Contrary to the Company's contention that it followed a strategy of regular purchases, the record shows that JCP&L's supply acquisition was erratic and irregular.

The Company did not actually time its purchases using the approaches and elaborate computer models described in its testimony. The actual decision-making that led to JCP&L's expenditure of billions of dollars remains opaque.

The Company's discovery responses also failed to provide much information on the development of the inputs to its models, the outputs of those models, or what actions were taken in response to the model results. In some cases, JCP&L used data that were of questionable relevance in computing purchasing targets. In most cases, the Company has not disclosed the data it used.

Even the Company's fundamental criterion in determining how much energy to purchase in the forward markets appears to have been flawed. Rather than attempting to minimize the costs of BGS supply for ratepayers, JCP&L focused on minimizing the monthly variation in its earnings.

Q: Please summarize your recommendations.

A: Based on my findings, summarized above, I recommend that Your Honor and the Board decline to allow any recover of deferred BGS balances at this time.

It is my understanding that the BPU Staff's Auditor's Report will be publicly released soon. I therefore reserve my right to file supplemental testimony based upon the Staff's Auditor's Report.

III. The Cost of the Company's Basic-Generation-Service Supply

Q: Has JCP&L provided any comparisons of the prices it paid for BGS supply, to other measures of the cost of power?

A: The Company has provided no comparison of its BGS costs directly to market prices. However, in RAR-BGS-5 it did provide a comparison of its monthly BGS costs to the BGS-equivalent costs (called provider-of-last-resort costs) of the other GPU companies, Pennsylvania Electric and Metropolitan Edison. This is an instructive comparison, since PennElec and MetEd were entirely at risk for the provider-of-last-resort costs until June 14, 2001, when the Pennsylvania Public Utilities Commission granted them the right to defer provider-of-last-resort costs in excess of the amounts allowed in rates. Even after June 2001, the Pennsylvania companies face deferral of their costs until 2006, and will have to write off any costs that cannot be recovered through the fixed CTC by 2010.

In contrast, JCP&L has known that all excess BGS costs are deferrable, that recovery could start in 2002 or 2003, and that it faces no firm termination date for recovery of BGS deferrals. Corporate power-supply planners would thus have every incentive to be especially careful in acquiring power for the Pennsylvania companies and to allocate the best available deals to the Pennsylvania companies.

Q: How do JCP&L's BGS costs compare to those of MetEd and PennElec?

A: The Company almost always paid more per MWh for purchases than the Pennsylvania companies did in the same month. See Schedule PLC-2. This computation excludes the costs of the NUG contracts and the transitional PPAs, which obviously vary between utilities.

The average price that PennElec and MetEd paid for non-NUG, non–transitional-PPA power (weighting the two companies equally) was about 12% less than the price JCP&L paid. At the prices paid by the Pennsylvania utilities, the Company's $1.92-billion bill for non-NUG, non–transitional-PPA power through July 2002 would have been $239 million less.

Q: Does the Company attempt to justify the differences between the power-supply prices of JCP&L and those of the Pennsylvania utilities?

A: Yes. In RAR-BGS-56 the Company argues that JCP&L's costs per MWh of BGS supply would be greater than those of its Pennsylvania affiliates for the following reasons:

- the Company has "higher peak requirements" that the other companies.[2]
- the "overall average cost of JCP&L's NUGs is significantly higher."
- "Shopping levels have been significantly higher in PennElec and MetEd than in JCP&L…thus reducing their power supply requirements compared to JCP&L."
- "Congestion costs [affect] JCP&L significantly more than" the other utilities.
- "JCP&L tends to have a higher load response due to extremely hot weather…due to the greater penetration of air conditioning."

Q: Do these arguments explain the differences in the costs of market purchases?

A: No, for the following reasons.

- The Company does tend to have a lower load factor than the Pennsylvania affiliates and a slightly higher percentage of energy used in the peak period. However, the Company has not offered any computation to demonstrate that these differences in load shape could explain the differential in prices.
- My comparison excludes NUG costs, so their costs do not explain the differentials.
- The higher shopping levels in Pennsylvania would tend to draw off customers with better load shapes, increasing the unit cost of power supply.

[2]The Company makes this point several times in different ways, as if it were a different cost driver each time.

- The Company may face higher congestion costs than the Pennsylvania affiliates, but it has not quantified those differences.
- The differentials are not driven by the summer air-condition load. In the summer months, JCP&L's power-supply costs per MWh have been relatively close to those of the Pennsylvania utilities. The divergences tend to be greater in the fall and winter than in the summer, as shown in Schedule PLC-2.

Q: How should the ALJ and the Board use the results you present in Schedule PLC-2?

A: The size of the differentials indicates that different procurement processes may have eliminated the deferrals, at least through the first three years of competition. This conclusion supports my recommendation that Your Honor and the Board deny recovery of any of the BGS deferral, for lack of a showing of prudence.

IV. Standard for Review

Q: Was the Company's BGS supply for the first three years of competition, in aggregate, a major financial commitment?

A: Yes. The BGS supply for this period cost over $3 billion, comparable to the cost of a nuclear power plant. Expenditures of this size are generally subject to the highest level of scrutiny.

Q: Was this procurement the continuation of an activity that JCP&L had been familiar with, prior to restructuring?

A: Not really. The Company, as part of GPU, was certainly familiar with purchasing and selling generation services with other utilities. However, with restructuring, JCP&L divested the bulk of its generation resources and became much more dependent on the market than it had been previously. Also, the Company's purchases were consequently from a restructured, nominally competitive, market rather than from other regulated utilities.

The novel restructured market was, in many ways, more complex than the regulated market that preceded it. In addition to installed (now unforced) capacity and energy in various time patterns (including the now-standard peak and off-peak periods), the Company needed to acquire ancillary services and pay the differential in market prices between the place at which it purchased energy and the place at which it took that energy off the PJM transmission system, such as by obtaining fixed transmission rights.

That there was no precedent for the Company's BGS purchases makes a high level of care—and a high level of documentation of procedures, decisions and outcome—particularly important.

Q: Why is documentation of procedures, decisions, and outcomes particularly important for a major and unfamiliar process such as the Company's BGS procurement?

A: Documentation is important for three different reasons. First, clear documentation is important for control of the process. The Company needed to make decisions on a daily basis, for acquisition of a number of different generation products (capacity, ancillary services, peak-period energy, off-peak energy, and other energy shapes), for various time periods (hourly, daily, annual, and various intermediate durations) and for physical products, financial transactions, and options. Many of these decisions would need to be made very quickly, with little opportunity for review or supervision, and by different people on different days. To maintain control over the process, JCP&L would need to have clear policies to guide staff and retain a clear trail recording the decisions made by staff, to ensure that they were following the guidelines.[3]

Second, for the Company to know whether it had developed an appropriate purchasing strategy it would need to know how the actions taken pursuant to the strategy worked out, including the price of the products and how well those products fit into the Company's actual power supply. In terms of price, JCP&L should have been curious regarding how the cost of the generation services it had purchased compared to spot prices and to forward prices for various durations: a day ahead, a month ahead, a year ahead, and so on. The Company should also be able to use its historical results in evaluating potential new strategies for timing purchases. In terms of the operation of its strategy, the Company should have been monitoring whether it was exercising the options it bought (and if not, whether the risk reduction was worth the price), whether the total costs of the options exceeded the cost of generation services they provided, and whether it was purchasing more or less power in the spot market than it had planned for.

Third, the Company should have maintained a high level of documentation to allow for the inevitable external review, including this proceeding.

Q: You have described the need to document various decisions regarding purchases of generation services and related options. Are there other processes, decisions, and outcomes that JCP&L should be prepared to document?

A: Yes. At the beginning of competition in 1999, the Company had a large number of NUG contracts, two utility contracts, the Transitional PPA from the TMI sale,

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[3]The example of banks crippled by "rogue" traders (such as Barings Bank, once one of Britains oldest before being ruined by a single trader) is instructive here.

and various company-owned generation resources contributing to the BGS supply. By the end of 1999, the utility contracts had terminated and most of the generation had been sold, and a capacity-only transitional PPA had been added in connection with the generation sale. The Company needed integrate these resources into its BGS portfolio, including scheduling, dispatch, and renegotiation of the contracts to increase their value or decrease their costs for BGS. The Company also needed to determine when it had excess generation services from long- and short-term purchases and from owned resources to resell into the market, and determine how to dispose of that excess.

Q: What policy analyses should JCP&L have produced in the course of its BGS procurement?

A: Early in the process—preferably by the time the PJM market opened and certainly by the time that JCP&L sold most of its generation to Sithe in November 1999—the Company should have developed an initial strategy for purchasing power from the competitive market. That strategy would have included rules for determining the following points:

- the percentage of each generation service that should be purchased in the forward contract market (as opposed to daily spot markets),
- the desired timing of the contract purchases (a week ahead, a month ahead, a year ahead),
- the form of contracts (for example, fixed prices versus prices tied to gas prices),
- the extent to which price risk should be hedged with options,
- how the above guidelines should vary with current spot and contract prices, volatility, and other factors.

Periodically, JCP&L should have reviewed the performance of its strategies and revised them.

Q: What data tracking did you expect JCP&L to have developed in conjunction with its BGS purchases?

A: I expected JCP&L to maintain a tabulation of each product that would allow the Company to determine the following.

First, for each purchase (or sale) that contributed to each day's supply of energy or capacity,

- when it made that purchase;
- the nature of the product purchased, such as standard products (e.g., 5 × 16 blocks of on-peak energy), specialty products (e.g., energy at certain peak hours), or bundles of peak and off-peak energy, capacity, fixed transmission rights, and ancillary services;
- the price;
- whether the purchase was the result of the exercise of an option, and if so, the date the option was purchased or sold, and its price.

Second, what purchases it made each day, including

- what period each purchase covered,
- the nature of the product and options purchased,
- the magnitude of purchases in MW or MWh.

Third, sales for resale made each day, with detail similar to the preceding item.

Fourth, what entities JCP&L purchased power from and sold power to, with special attention to demonstrating that transactions with GPU and FirstEnergy affiliates were at market prices (or in that case of GPU, at prices determined by long-standing contracts), Finally, how JCP&L dealt with price differentials from standard PJM delivery points to its delivery points,

Q: What other analyses would you expect JCP&L to have performed periodically during the period in which it was purchasing BGS supply for its customers?

A: The Company should have been periodically reviewing the performance of the guidelines in the following two ways:

- by comparing the costs of the guideline recommendations to the costs under other approaches,
- by reviewing its staff compliance with guidelines, and the reasonableness of any deviations from the guidelines (including whether those deviations indicated a need to change an underlying guideline).

V. The Company's Performance

Q: What approaches can the Board take in evaluating the Company's performance in minimizing the cost of BGS supply for its customers?

A: The Board could examine JCP&L's process, its results, or both. The process review would look at whether the Company established a planning-and-procurement process that included the aspects I discussed in the previous section, whether the Company followed its own rules and guidelines, and whether its decisions were reasonable. The results review would compare JCP&L's prices to other benchmarks, including procurement by other utilities and various market indices. There is some overlap in the approaches, since the process review includes determining whether JCP&L was reviewing its results and using that information to improve its procurement.

Q: Which approach is preferable?

A: The two types of review perform different functions and should be conducted in tandem. The results review by itself cannot establish prudence or imprudence, since even the most careful and thoughtful analysis will sometimes result in higher costs due to bad luck. On the other hand, the process review by itself cannot determine the magnitude of the damages from any imprudence.

Q: Is the review by the ALG and the Board in this proceeding limited to a single decision or policy developed by JCP&L?

A: No. The Company had the opportunity to revise its procurement policies over time, as highlighted by the separate testimony of Mr. Mascari on procurement prior to GPU's merger with FirstEnergy and of Mr. Stathis on procurement after the merger.[4] The Company also clearly changed its procurement pattern (whether by policy or otherwise) at other times in the BGS period.

In addition to differences in practices over time, the Company had different decisions to make regarding different products. Most of JCP&L's planning appears to have addressed procurement of on-peak energy, but it also needed to obtain off-peak energy, capacity, and ancillary services, and had the opportunity to use various risk-management strategies, including options. In order to find JCP&L's activities to be prudent, Your Honor and the Board would need to be able to review the Company's choices for each product, in each time period, including decisions to use or eschew risk-management techniques.

Q: How well has JCP&L demonstrated that it has met the standards of care that you described above?

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[4]It is not clear that the Company ever had a clear policies or followed them if it did.

A: Not well at all. The Company must have known since 1999 that its procurement policies for BGS and its effective execution of that policy were of great importance.[5] Yet JCP&L failed to provide even the simplest information on a timely basis. In many cases its replies were delayed until the end of the discovery period, making follow-up data requests impossible; see Schedule PLC-3.

The Company took months to provide documents and data that supported its BGS procurement. In many cases, the responses remain incomplete in such critical areas as the record of supply acquisition.

Q: Was the Company able to explain and document its procurement policies for BGS?

A: Not in any consistent manner. The Company was not even able to provide the "physical units by type (e.g., MWh on-peak energy, MWh off-peak energy, kW-month of UCAP) provided by each supply and purchase for each month in Schedule SDM-1B" (RAR-BGS-27). In short, the Company can ask for millions (even hundreds of millions) of dollars each month in each of a dozen categories, but cannot say what it purchased with those expenditures.

For some products, JCP&L provides internal procedures documents, such as that for heat-rate hedges (Attachment RAR-BGS-55(1)), which details procedural controls and mathematical guidelines for "unwinding" or terminating the hedges as the exercise date approaches. In general, the discovery responses describe little more than the most general approaches, and do not describe the

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5The stipulation that JCP&L signed in BPU Dockets Nos. EO97070458, EO97070459, and EO97070460 (at ¶7) states, "The stipulating parties agree that reasonable and prudent costs incurred in accordance with the foregoing, as determined by the Board, shall be recoverable in rates."

rules used in deciding how much of what product for some future period should be purchased on what day (or week, or month).

The Company provided similar descriptions of procedural controls in response to RAR-BGS-54, which asked how "JCP&L balanced its BGS supply for on-peak energy, off-peak energy, and capacity, with the amounts acquired by the beginning of the month." The explanation of the purchasing rules is limited to the choice between day-ahead and real-time markets (the Company preferred the former), ignoring entirely all the intra-month forward purchases shown in Attachment RAR-BGS-54(2).

In some cases, JCP&L provides a description of its procurement policy that is completely inconsistent with its actual procurement. In RAR-BGS-80 the Company asserts that its strategy adopted in August 1999 required that "supply targets for the volatile summer months were to be filled at least six months in advance." Yet the data in RAR-BGS-54(a) show that JCP&L had not filled the summer 2000 on-peak energy targets six months earlier (which would be December for June, January for July, and February for August). The Company's on-peak energy supply for these months remained thousands of MW short until April.[6]

While Mr. Stathis claimed that JCP&L analyzed volatility in the PJM capacity market, the Company was not able to provide any such analyses even after being given a second opportunity (RAR-BGS-124, -135).[7]

Q: To what extent has the Company provided a detailed tabulation of its BGS-supply acquisition?

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[6]While the Company's testimony implies that it planned ahead for all types of generation services required for BGS, its formal target-setting involved only energy for the on-peak period.

[7]Instead the Company provided market prices at different points in time.

A: The Company's documentation of its supply acquisition has been very spotty. It was not able to provide a full accounting of its purchases, as requested in RAR-BGS-27.

The Company clearly compiled some of these data, since it was able to provide the timing and pricing of intra-month energy and capacity purchases in Attachment RAR-BGS-54(2). It did not provide similarly comprehensive information for the larger purchases prior to the start of the delivery month, although it provided some examples in RAR-BGS-72.

Attachment RAR-BGS-55(2) lists the dates and prices of some options purchased (and, in one case, sold) by JCP&L, but does not include the more-complex cross-commodity transactions discussed in Attachment RAR-BGS-55(1).

In Attachment RAR-BGS-77 the Company provides details on six swaps between the PJM Western Hub and the PJM Eastern Zone or JCPL zone, and one between the PJM Eastern Zone and the JCPL zone.

The documents from the morning meetings described by Mr. Stathis (Direct at 7) do not include any proposed or actual decisions regarding power purchases.

Q: Was the Company able to support its witnesses' prefiled testimony about its BGS-procurement strategies and procedures?

A: No. Despite repeated requests for analyses and reports underlying JCP&L's procurement decisions, the Company has not provided documentation supporting the claims of its witnesses about the procurement process, including Mr. Mascari's description (Direct at 8–11) of the role of the "X analysis" and (Direct at 12) of dollar-cost averaging, or Mr. Stathis's description (Direct at 10–11) of acceleration of purchases in February 2002 or (Direct at 7) of the morning meetings on short-term procurement.

For example, Mr. Stathis describes the morning meetings as assessing "current regional, national and international energy market conditions (weather, generation, generation outages, transmission outages, natural gas and oil markets) and their impact on short- and long-range energy prices," reviewing "PJM load and price forecasts for both day-ahead and real-time PJM pricing points," and (Direct at 7) analyzing "congestion within PJM." He claims that the meetings then developed volume targets, discussed types of products (from real-time to next-month forwards), and established price ranges for acquisition of the preferred products.[8] This all sounds very appropriate.

Unfortunately, when asked for "full and complete copies of all documents including workpapers, studies, analyses, meeting minutes, PJM load forecasts, and PJM price forecasts from mathematical models used at each morning meeting for short term supply planning," all that JCP&L could provide was a pile of 10-day graphs of load and weather forecasts, some with JCP&L's hourly energy supply on the same graph, and a smaller number of 10-day forecasts for the day-ahead energy price at the Western Hub. There were no analyses of energy market conditions, generation outages, transmission outages, real-time PJM pricing, congestion within PJM, volume targets, types of products, or price ranges.

Q: What did Mr. Mascari mean by dollar-cost averaging in his discussion on page 12 of his direct testimony?

[8] Mr. Stathis's testimony on nature and use of the price ranges is not totally clear and no examples of those ranges have been provided.

A: That's not easy to determine, but he certainly did not really mean dollar-cost averaging, which is an investment guideline under which the investor purchases the same dollar amount of an investment on each day (or week, or month, depending on the size of the investment). The principle behind dollar-cost averaging is that, since the investor is spending the same amount of money each day, he will end up buying more shares (or other units) on days when share price is low and fewer on days when share prices are high. As a result, the investor will tend to own more shares after a sufficiently lengthy round of dollar-cost investing than had he or she spent the same amount of money buying an equal number of shares each day.

Unfortunately, the Company was not able to use dollar-cost averaging in purchasing BGS supply. Rather than having a fixed amount of dollars to spend, JCP&L had to purchase the amount of energy, capacity, and other generation services the BGS required.[9]

Q: How did the Company clarify Mr. Mascari's testimony on discovery?

A: The Company defined dollar-cost averaging as "a process of small purchases each month of the procurement planning horizon" (RAR-BGS-50 (a)). The explanation suggests that JCP&L was pursuing a strategy of buying, in each month, the same amount of energy for a particular future month. That is a better idea than buying all the power in one day, or one week, since that might happen to be a high-priced period.

This explanation is not the same as dollar-cost averaging, as widely understood, and does not even capture the basic idea of spending the same amount in each time period.

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[9] This task was further complicated by uncertainty in that need, which varied with general load growth, weather, switching rates, and generation (principally NUG) outages.

Q: Did JCP&L actually follow a strategy that resembled dollar-cost averaging?

A: No. In Attachment RAR-BGS-51(1), the Company provides the power-supply targets it set in each month (or sometimes twice a month) for each future month's on-peak energy supply, as well as its plans for filling those targets month by month. In Attachment RAR-BGS-52, JCP&L provides the extent to which it had filled those targets, month by month. These responses demonstrate no tendency to spread acquisitions evenly over time.

For example, Attachment RAR-BGS-52 indicates that JCP&L started in December 1999 with 1,927 MW of its 2,851 MW supply target for August 2000, giving it eight months to acquire about 900 MW. In mid-January, JCP&L raised its target to 4,382 MW, but it did not add any supply until early March, when it bought 200 MW. This left the Company 2,200 MW short with five months to go, implying a required fill rate of 400 MW or so per month, or roughly 100 MW per week. In the first half of March, JCP&L added another 100 MW of supply, and another 500 MW in the second half. These procurement patterns were far from the steady pattern of dollar-cost averaging. But the pattern got still stranger.

Attachment RAR-BGS-52 indicates that in the first five days of April JCP&L acquired 1,350 MW of supply, more than 60% of the shortfall projected in January. The Company had reduced its target by about 160 MW, so the massive April purchase nearly filled the target, leaving only 100 MW that JCP&L filled in June.

Q: Do the Company's other responses confirm this pattern of erratic purchases?

A: Yes. In Attachment RAR-BGS-144(1) JCP&L provides data on bilateral purchases and sales by transaction date and delivery date. I cannot reproduce the values in Attachment RAR-BGS-52 from the data in Attachment RAR-BGS-144(1), in part because Attachment RAR-BGS-52 would include other supplies. Nonetheless, Attachment RAR-BGS-144(1) shows a similarly erratic pattern, with JCP&L purchasing 1,050 MW of on-peak energy for June–August on March 31, 2000.[10]

Q: Was August 2000 the only month for which the Company's procurement deviated from the steady fill pattern of the "dollar-cost averaging" approach?

A: No. The deviations are numerous and varied. For each supply month, December 2001 through July 2002, Schedule PLC-4 provides plots of the target, target fill, and actual fill for that supply month, as of the midpoint of each earlier month.

These graphs show a pattern much more complicated than the evenly spread transactions the Company describes. In many cases, the Company sold off supply that it expected to need later. For some months, such as February and April 2002, JCP&L continued buying on-peak energy while its target was falling. The result was that JCP&L had hundreds or thousands of megawatts of extra on-peak energy going into the target month. For some months, as the target fill rose, the Company alternately increased and decreased actual fill (as for January 2002, February 2002, and June 2002). For other months the actual fill was reduced to below the target fill (as for January 2002). For December 2001 the actual fill was held almost constant, seemingly independent of changes in the target fill and the target.

Q: What were the exact rules that JCP&L used to determine the amount of energy purchased each day?

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[10]This 1,050 MW is shown as a single transaction (number ABJ132), but is presented as three entries of different megawatts and different prices.

A: The Company asserts (Mascari at 8) that it had specific rules for deciding how much power it should purchase in each month for each future month. However, the Company has not provided any contemporaneous documents that lay out such rules. In Attachment RAR-BGS-51(1) the Company shows two sets of rules for acquisition targets. The later rules, which the Company says it used starting in February 2001, requires acquisition of 100% of the target two months prior to the delivery month, and 5% less every preceding month. If that was the Company's rule, it was rarely honored.

The earlier rules, in place from August 1999 to at least November 2000, required 100% fill for summer and winter months (January, February, June, July, August, and September) just one month prior to delivery. For other delivery months, JCP&L was content with procuring as little as 50% of the target of the prior month, requiring procurement of as much as 50% of the target in the delivery month in addition to any other energy required for that month. The Company's target fill rates in earlier months varied widely; for the summer months, the Company's plan was to fill 10% in the third month before delivery, 20% two months before delivery, and 40% in the last month before delivery. As noted in RAR-BGS-53, the Company actually filled its target well before required by its target fill rates.

Oddly enough, in a footnote, the Company declares that its dollar-cost averaging policy was never as clear as its witnesses' testimony would imply. Note 1 of Attachment RAR-BGS-51(1) states that the target fill rates for 1999 and 2000 were only minimal values, and that "additional MWs could be purchased…dependent upon the prevailing forward price relative to Budget, and the remaining unpurchased (open position) MW." The Company has not provided the "Budget" values or formulae used in this computation, or any documents that record decisions to purchase additional energy. While it is not clear that JCP&L ever performed the analyses described in that note, it is clear that the Company was not following a simple "process of small purchases each month" as asserted in RAR-BGS-50 (a).

Q: How did the Company select between and among the "potential procurement products" that Mr. Stathis described?

A: The Company provided no rules, guidelines, or formulas for making these choices (as requested in RAR-BGS-121) but only a general description of its approach.

Similarly, in its explanation of the choice between day-ahead and real-time procurement of energy, JCP&L vaguely states that "there may have been identifiable trends or conditions that would have caused JCP&L to bid a limited portion of its load in the real-time market," considering "market trends over different planning horizons" (RAR-BGS-122). That response fails to provide even a single example of the types of trends or conditions that would cause JCP&L to rely on the real-time market.

Q: What was JCP&L's guiding principle for procuring BGS supply in the pre-merger period?

A: Mr. Mascari states (Direct at 8) that the Company's objective was to "minimize the difference between projected MEC [market energy and capacity] revenues and BGS costs." This objective is also stated in the official GPU Power Market Evaluation procedure provided in Attachment RAR-BGS-51(2), as minimizing "variations in energy supply Pre-tax Earnings due to weather."

Q: Was this an appropriate primary objective for BGS procurement?

A: No. The Company's primary objective should have been to minimize expected BGS costs. Minimizing the *variation* in costs from month to month can increase the *total level* of costs over the course of a year. In some months, the BGS costs were below the MEC revenues, so minimizing the differences would require the Company to increase BGS costs.[11] Reducing variability also has some value, but JCP&L's sole focus on that objective is inappropriate.

Q: How did the Company pursue this objective?

A: The Company has not fully explained that. Mr. Mascari asserts (Direct at 8) that the Company used "various mathematical models" to calculate the monthly supply percentage and minimize the difference between projected MEC revenues and BGS costs. On discovery, JCP&L discussed (1) production-costing models (e.g. PROMOD, in Attachment RAR-BGS-51(2)); (2) Nostradamus, which its vendors have described as "a short-term, neural network-based demand and price forecasting system;" and (3) two models that were apparently used in some way to set the supply targets. These two latter models are as follows:

- The spreadsheet X-model described by Mr. Mascari (e.g., Schedule CAM-5), which simply projects the cost of on-peak energy for BGS supply for two weather conditions (mild and severe), and for a range of forward energy purchases.
- The Host model, a commercial risk-management program that JCP&L has only minimally described (RAR-BGS-51, -52, -64) but that appears to require a large number of judgmental inputs and a final judgment about the use of the results. The Company has not provided the details of the model

[11] I doubt that JCP&L intentionally increased BGS costs to bring them closer to the MEC revenues in those months; this situation simply illustrates the irrelevance of the Company's stated objective.

inputs, results, or management's subsequent judgements about the use of those results. Host apparently replaced the X-model in February 2001.[12]

The record regarding the Company's use of the X-model is fairly clear, at least in conceptual terms. The Company's failure to provide the specific values and the actual spreadsheets it used renders any detailed review impossible. In any case, the Company was misguided in pursuing the X-model exercise of selecting the level of forward contracts that would produce the same after-tax earning to the company under two arbitrarily-selected weather conditions, rather than attempting to minimize customer costs.

The Company's documentation of its use of Host is much more limited. The Company provides procedural rules for the use of the Host model (RAR-BGS-51, -54), rather than the requested descriptions of "all computations and data" (-51d) used to set target, "how JCP&L decided whether to purchase or sell in the multi-day forward markets, in the day-ahead market, or in hourly or real-time markets" (-54a), and "copies of all documents including workpapers, studies, analyses and meeting minutes presenting JCP&L's policies" (-54b).

Q: Were the results of these models stable over time?

A: No. The targets reported in RAR-BGS-51 rise and fall dramatically from month to month. For example, the target for August 2000 jumped about 50% between January 3 and 17, 2000. The target for November 2001 fell from 1,744 MW in May, to 1,406 MW in July, 1,063 MW in September, and 615 MW in October.

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[12]It is not clear exactly what policies, if any, were guided by Host. From Attachment RAR-BGS-51(1), it appears that Host always prescribed on-peak energy fill rates of 5% of the target per month, leading to filling the target two months before the delivery date (e.g., filling the June target by mid-April). Since this fill-rate schedule did not change over time, it was probably an input to Host, rather than an output. In any case, JCP&L did not observe the target fill rates.

Q: How did the Company's procurement policy change after the merger with FirstEnergy?

A: Mr. Stathis (Direct at 6) describes a policy change in which the Company, under FirstEnergy's management, decided to relax controls on early energy procurement and start buying additional energy in response to falling forward prices. Going into November 2001, JCP&L already had committed more than its target for February. Nonetheless, the Company made large additional purchases in November and December, as the target was falling, resulting in commitments that were about 1,000 MW above target, some of which JCP&L sold off in January. In February 2002 JCP&L accelerated acquisition of peak energy for April–June 2002. These acquisitions pushed supply for May and June to about 400 MW above the Company's target, and added about 400 MW to the surplus of supply JCP&L already had for April.

In contrast, the Company added no net supply for July 2002 in the period from September 2001 (when the actual fill was between the target fill and the target) to May 2002 (when the fill was 1,000 MW less than both the target and the target fill) and sold off 700 MW in June, leaving the Company short 1,500 MW going into the supply month.

Q: What was the basis for this acceleration in acquisition for some months following the merger?

A: The Company's explanations for this decision are inconsistent and do not address the decision to acquire energy above the targets the Company set. Mr. Stathis testified (Direct at 6) that JCP&L decided "to accelerate purchases…if market prices were attractive vis-à-vis historical norms." In RAR-BGS-115(b), JCP&L defines those "historical norms" as "the simple 3-year monthly average for the following PJM Western Hub forward contracts," and then lists every month from December 2001 to July 2002. The attached workpapers show computations of monthly actual average real-time and day-ahead on-peak prices over a three-year period (1998–2001), rather than forwards. Forwards are not actual prices.

In contrast, Attachment RAR-BGS-64(2) describes the setting of the "lock and load…target prices that would trigger immediate filling of Host targets," which would be a function of current gas prices and the average and standard deviation of average monthly market prices from 1996 to 2000. Since the PJM competitive market started in 1999, the earlier data were computed from cost-based dispatch prices, rather than actual bidding. Attachment RAR-BGS-64(2) describes target prices for weekend and off-peak energy, as well as on-peak energy.

The Company has not reconciled these inconsistent descriptions of the single decision leading to the large purchases in February 2002. Nor has JCP&L explained how actual prices in earlier years (or past prices for forwards) informed its decision to make these purchases.

Q: Was this actually a change from JCP&L's previous policy?

A: Not really. As I have described above, the Company's actions do not show that it had any coherent policy before or after the merger, so it is hard to say that the policy changed. Creating or exacerbating surpluses for three months into the future (April–June, for the February procurement decisions) was nothing new for JCP&L; in February 2001, the Company purchased additional supply for June, even though it was already more than 600 MW in surplus (Attachments RAR-BGS-52(1), 53).

Q: What was JCP&L's basis for these acquisitions?

A: Mr. Stathis describes a period of falling forward prices in November 2001 through early February 2002. RAR-BGS-64(2) describes a procedure for selecting forward prices that would justify locking in the supply target. The Company has not explained why it locked in so much supply above its targets for April–June, or why the Company did not lock in any additional supply for July supply in February. Nor has the Company been able to provide the derivation of the trigger prices for locking in large amounts of additional supply.

Q: Has JCP&L provided comparisons of its costs of purchasing BGS supply to other measures of costs?

A: No. The Company does not appear to have performed such reviews. In fact, the Company objects to the very idea of reviewing its procurement performance.

- In RAR-BGS-132, JCP&L refuses to compare the costs of its congestion hedges to the actual costs of congestion, on the grounds that "an after the fact comparison such as is requested has no relevance in determining whether or not the acquisition of a hedge was an appropriate action at the time such acquisition decision was made."
- In RAR-BGS-127, JCP&L similarly asserts that it did not analyze whether the post-merger acceleration of procurement had "reduced the cost of BGS supply as compared to the pre-merger procurement strategy" because "JCP&L does not believe such after-the-fact analyses are relevant because the prudence of the actions must be judged in light of the facts and circumstances as they existed at the time the decision was made and cannot be reassessed with 20/20 hindsight."
- In RAR-BGS-12(a), JCP&L states that it did not retain the market-price data that JCP&L received from brokers at the time it was making purchases, because those data served no further "operational" purpose. Of course, the data describing the pricing options that JCP&L staff faced at

the time they made their decisions would be essential in any review of staff performance or of the guidelines under which the staff was operating.

- In RAR-BGS-14(a), the Company similarly states that it did not retain the broker price quotes contemporaneous with its sales into the market.
- In RAR-BGS-66, JCP&L states that it cannot provide published data in its possession due to copyright concerns, and that it had disposed of all contemporaneous data due to lack of an “operational reason” for retaining the data.
- In RAR-BGS-124, JCP&L states that it did not retain information on the capacity offers, “market intelligence,” notes of discussions with counter-parties, or the Company’s “resultant views”—that is, its conclusions and decisions.

Q: Are the Company’s complaints about “after-the-fact comparisons” correct?

A: No. It is true that the outcome of any one decision, out of many, does not determine whether it was “an appropriate action at the time such acquisition decision was made.” Good decisions sometimes have bad outcomes. But JCP&L should have been conducting after-the-fact comparisons throughout the BGS-procurement period to guide its procurement. Furthermore, the Board needs to see the results of after-the-fact comparisons today.

The Company should have been conducting after-the-fact comparisons throughout the BGS-procurement period because information on the performance of a strategy is vital to determination of whether the strategy should be continued. If every transaction of a particular type that JCP&L made turned out to be uneconomic, prudent management would require that the use of that type of transaction be re-examined, restricted, or stopped entirely. I do not believe that JCP&L could prudently acquire BGS supply without such information.

The Board needs to see the results of after-the-fact comparisons today to determine whether JCP&L should have identified and corrected problems in its procurement strategies. The Company's refusal to provide such data prevents the Board from determining that JCP&L's procurement was prudent.

Q: Has JCP&L demonstrated that it managed the NUG contracts to minimize their contribution to BGS costs?

A: No. The Company responded to a request for documents related to restructuring the NUG contracts by stating that the documents were voluminous and would be made available in Reading, Penn. (RAR-BGS-142). The Company has failed to demonstrate any management of NUG contracts to minimize NUG costs.

Q: Has JCP&L demonstrated that it managed its existing load-control and demand-response programs to minimize BGS costs?

A: No. Mr. Stathis asserts (Direct at 8) that the implementation of demand-response programs is controlled by the JCP&L Commodity Sourcing Department (the unit responsible for BGS procurement), and that those programs reduce BGS costs "by minimizing energy to be procured at high-cost hours and by muting demand-induced price spikes." In RAR-BGS-63, the Company discusses these programs in general but does not even claim that it used the programs to minimize BGS costs, let alone provide the requested description of how it optimized the use of the demand-response programs to reduce BGS costs.

Q: Do you have any concluding comments?

A: I do have one comment on the Market Transition Charge. It is my understanding that the Company has included the cost of the Freehold NUG buyout, without having received approval of that buyout from the Board.

Q: Does this conclude your testimony?

A: Yes, at this time. Due to the volume of discovery responses that JCP&L has provided in just the last couple weeks, I have not completed my review, and I may need to update this testimony.

Schedule PLC-1

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SUMMARY OF PROFESSIONAL EXPERIENCE

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

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

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

EDUCATION

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

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HONORS

Chi Epsilon (Civil Engineering)

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Institute Award, Institute of Public Utilities, 1981.

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

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

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

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

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

“Cost-Effectiveness Analysis.” Presentation as part of “Effective DSM Collaborative Processes,” a week-long training session for Ohio DSM advocates sponsored by the Ohio Office of Energy Efficiency, August 1993.

“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.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Allocation of costs and benefits to rate classes.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Performance incentives proposed for the Boston Edison company.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Review of proposed performance standards and valuation of performance.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

186. **New Jersey BPU** EX1050303; New Jersey electric companies' procurement of basic supply; New Jersey Ratepayer Advocate. August 2001.

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

188. **NY PSC** 0-E-1208; Consolidated Edison rates; City of New York. October 2001.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Schedule PLC-2:
Comparison of JCP, PennElec, and MetEd Purchases

	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00
JCPL price	51.39	38.27	32.08	27.73	33.36	38.65	32.73	29.87	30.29	39.64	51.27
MetEd price	51.72	24.38	29.29	24.30	24.47	35.15	30.51	57.23	34.28	38.06	52.47
PennElec price	54.51	26.00	26.11	26.92	24.33	32.75	31.77	41.46	31.83	30.62	46.02
ME/JC price ratio	101%	64%	91%	88%	73%	91%	93%	192%	113%	96%	102%
PN/JC price ratio	106%	68%	81%	97%	73%	85%	97%	139%	105%	77%	90%
JCPL non-NUG, non-TPPA costs	57,012,884	33,132,510	35,066,489	43,499,907	34,164,461	42,249,979	43,110,272	32,342,782	20,766,284	32,745,731	84,873,060
JCPL costs adjusted by ME/JC price ratio	57,378,992	21,107,149	32,016,754	38,119,284	25,060,083	38,423,978	40,186,202	61,967,774	23,501,757	31,440,528	86,859,557
JCPL costs adjusted by PN/JC price ratio	60,474,262	22,509,675	28,540,712	42,229,264	24,916,707	35,800,435	41,845,809	44,892,258	21,822,081	25,294,508	76,182,138
Cost Difference per ME/JC ratio adjustment	(366,107)	12,025,361	3,049,735	5,380,623	9,104,378	3,826,001	2,924,070	(29,624,992)	(2,735,473)	1,305,203	(1,986,496)
Cost Difference per PN/JC ratio adjustment	(3,461,378)	10,622,835	6,525,777	1,270,643	9,247,754	6,449,544	1,264,463	(12,549,476)	(1,055,797)	7,451,223	8,690,922

Schedule PLC-2:
Comparison of JCP, PennElec, and MetEd Purchases

	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01
JCPL price	77.66	80.86	38.75	32.99	33.28	40.84	45.50	39.92	43.37	49.96	43.87
MetEd price	69.00	77.87	36.19	30.93	31.65	39.07	38.63	38.09	41.75	47.30	41.45
PennElec price	61.31	70.48	37.55	31.20	31.09	38.68	38.25	37.60	42.49	42.17	40.46
ME/JC price ratio	89%	96%	93%	94%	95%	96%	85%	95%	96%	95%	94%
PN/JC price ratio	79%	87%	97%	95%	93%	95%	84%	94%	98%	84%	92%
JCPL non-NUG, non-TPPA costs	126,177,173	110,588,812	35,033,771	30,699,513	24,660,201	26,229,832	39,942,654	28,777,585	30,007,012	32,020,819	40,436,512
JCPL costs adjusted by ME/JC price ratio	112,106,940	106,499,515	32,719,282	28,782,538	23,452,384	25,093,035	33,911,752	27,458,372	28,886,160	30,315,948	38,205,913
JCPL costs adjusted by PN/JC price ratio	99,612,703	96,385,685	33,948,855	29,033,792	23,037,429	24,842,554	33,578,165	27,105,140	29,398,154	27,027,981	37,293,396
Cost Difference per ME/JC ratio adjustment	14,070,233	4,089,297	2,314,489	1,916,975	1,207,816	1,136,797	6,030,902	1,319,213	1,120,852	1,704,871	2,230,599
Cost Difference per PN/JC ratio adjustment	26,564,471	14,203,127	1,084,917	1,665,721	1,622,772	1,387,278	6,364,489	1,672,445	608,858	4,992,838	3,143,116

Schedule PLC-2:
Comparison of JCP, PennElec, and MetEd Purchases

	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02
JCPL price	65.10	84.73	97.44	44.66	43.48	34.08	38.62	40.25	38.82	36.70	40.63
MetEd price	52.02	73.45	81.50	30.73	23.92	23.57	21.12	30.32	29.38	24.64	27.98
PennElec price	53.24	75.91	83.42	37.74	30.78	25.45	26.95	32.34	32.39	26.57	31.98
ME/JC price ratio	80%	87%	84%	69%	55%	69%	55%	75%	76%	67%	69%
PN/JC price ratio	82%	90%	86%	85%	71%	75%	70%	80%	83%	72%	79%
JCPL non-NUG, non-TPPA costs	102,444,705	121,252,213	175,214,353	38,614,431	34,091,092	38,828,291	34,502,918	44,017,465	32,059,154	37,119,543	35,403,126
JCPL costs adjusted by ME/JC price ratio	81,861,345	105,110,056	146,551,413	26,570,118	18,754,805	26,853,956	18,869,398	33,158,001	24,263,214	24,921,677	24,380,494
JCPL costs adjusted by PN/JC price ratio	83,781,199	108,630,420	150,003,913	32,631,183	24,133,482	28,995,892	24,076,998	35,367,076	26,748,995	26,873,740	27,865,911
Cost Difference per ME/JC ratio adjustment	20,583,360	16,142,157	28,662,939	12,044,313	15,336,287	11,974,335	15,633,521	10,859,464	7,795,941	12,197,866	11,022,632
Cost Difference per PN/JC ratio adjustment	18,663,505	12,621,793	25,210,439	5,983,248	9,957,610	9,832,399	10,425,921	8,650,389	5,310,159	10,245,803	7,537,215

Schedule PLC-2:
Comparison of JCP, PennElec, and MetEd Purchases

	May-02	Jun-02	Jul-02	Totals through Jul-02
JCPL price	36.61	49.22	69.01	45.88
MetEd price	25.51	47.73	63.75	40.26
PennElec price	31.28	43.93	60.88	39.90
ME/JC price ratio	70%	97%	92%	88%
PN/JC price ratio	85%	89%	88%	87%
JCPL non-NUG, non-TPPA costs	37,984,517	65,585,631	139,799,814	1,920,455,498
JCPL costs adjusted by ME/JC price ratio	26,467,769	63,600,206	129,144,155	1,694,000,505
JCPL costs adjusted by PN/JC price ratio	32,454,403	58,536,708	123,330,136	1,669,201,761
Cost Difference per ME/JC ratio adjustment	11,516,748	1,985,424	10,655,659	226,454,994
Cost Difference per PN/JC ratio adjustment	5,530,114	7,048,923	16,469,678	251,253,737

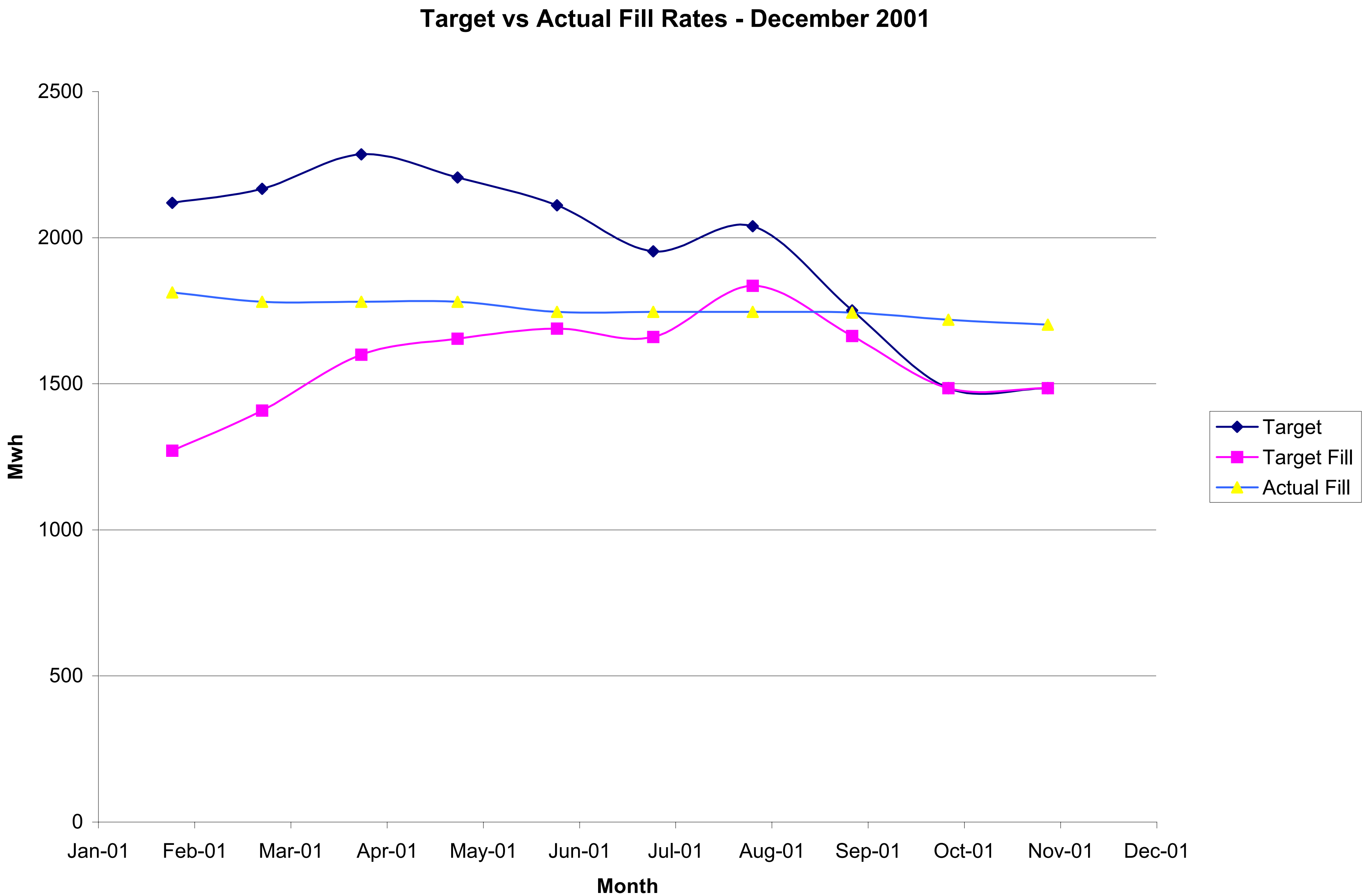
Schedule PLC-3:
Timing of JCP&L Responses to BGS Discovery

Question	Asked	Replied
RAR-BGS-1	9/9/2002	10/3/2002
RAR-BGS-2	9/9/2002	10/10/2002
RAR-BGS-3	9/9/2002	10/10/2002
RAR-BGS-4	9/9/2002	10/10/2002
RAR-BGS-5	9/9/2002	11/25/2002
RAR-BGS-6	9/9/2002	11/25/2002
RAR-BGS-7	9/9/2002	10/10/2002
RAR-BGS-8	9/9/2002	11/13/2002
RAR-BGS-9	9/9/2002	11/14/2002
RAR-BGS-10	9/9/2002	10/2/2002
RAR-BGS-11	9/9/2002	10/16/2002
RAR-BGS-12	9/9/2002	10/10/2002
RAR-BGS-13	9/9/2002	10/1/2002
		Supplemental 11/26/2002
RAR-BGS-14	9/9/2002	10/1/2002
RAR-BGS-15	9/9/2002	10/1/2002
RAR-BGS-16	9/9/2002	10/21/2002
RAR-BGS-17	9/9/2002	10/4/2002
RAR-BGS-18	9/9/2002	10/3/2002
RAR-BGS-19	9/9/2002	10/3/2002
RAR-BGS-20	9/9/2002	10/1/2002
RAR-BGS-21	9/9/2002	10/3/2002
RAR-BGS-22	9/9/2002	10/3/2002
RAR-BGS-23	9/9/2002	10/3/2002
RAR-BGS-24	9/9/2002	10/3/2002
RAR-BGS-25	9/9/2002	10/3/2002
RAR-BGS-26	9/9/2002	10/3/2002
RAR-BGS-27	9/9/2002	11/14/2002
RAR-BGS-28	9/9/2002	10/10/2002
RAR-BGS-29	9/9/2002	10/10/2002
RAR-BGS-30	9/9/2002	11/13/2002
RAR-BGS-31	9/9/2002	10/10/2002
RAR-BGS-32	9/9/2002	11/13/2002
RAR-BGS-33	9/9/2002	11/13/2002
RAR-BGS-34	9/9/2002	11/14/2002
RAR-BGS-35	9/9/2002	10/21/2002
		Supplemental 11/26/2002
RAR-BGS-36	9/9/2002	10/21/2002
RAR-BGS-37	9/9/2002	11/13/2002
RAR-BGS-38	9/9/2002	11/14/2002
RAR-BGS-39	9/9/2002	10/21/2002

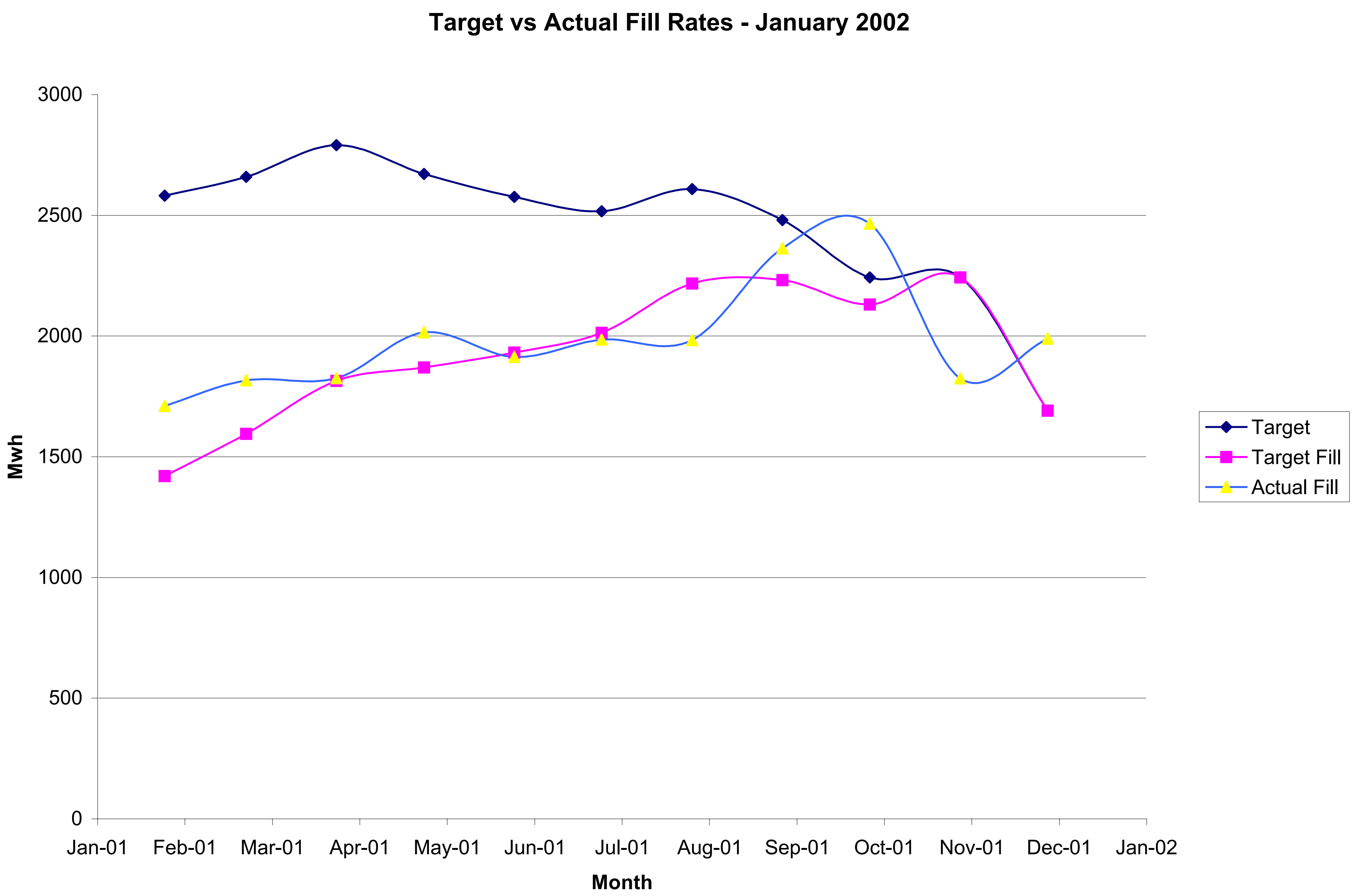
Question	Asked	Replied
RAR-BGS-40	9/9/2002	10/23/2002
RAR-BGS-41	9/9/2002	11/8/1001
RAR-BGS-42	9/9/2002	11/8/1001
RAR-BGS-43	9/9/2002	10/3/2002
RAR-BGS-44	9/9/2002	10/2/2002
RAR-BGS-45	9/9/2002	10/21/2002
RAR-BGS-46	9/9/2002	11/7/2002
RAR-BGS-47	9/9/2002	11/13/2002
RAR-BGS-48	9/9/2002	11/13/2002
RAR-BGS-49	9/9/2002	10/3/2002
RAR-BGS-50	9/9/2002	10/20/2002
RAR-BGS-51	9/9/2002	11/14/2002
RAR-BGS-52	9/9/2002	11/14/2002
RAR-BGS-53	9/9/2002	11/14/2002
RAR-BGS-54	9/9/2002	11/13/2002
RAR-BGS-55	9/9/2002	11/14/2002
RAR-BGS-56	9/9/2002	11/14/2002
RAR-BGS-57	9/9/2002	10/21/2002
RAR-BGS-58	9/9/2002	10/14/2002
RAR-BGS-59	9/9/2002	11/14/2002
RAR-BGS-60	9/9/2002	11/13/2002
RAR-BGS-61	9/9/2002	10/16/2002
		Supplemental 11/25/2002
RAR-BGS-62	9/9/2002	10/10/2002
RAR-BGS-63	9/9/2002	10/20/2002
RAR-BGS-64	9/9/2002	11/14/2002
RAR-BGS-65	9/9/2002	11/14/2002
RAR-BGS-66	9/9/2002	10/21/2002
		Supplemental 11/15/2002
RAR-BGS-67	9/9/2002	11/14/2002
RAR-BGS-68	9/9/2002	11/14/2002
RAR-BGS-69	9/9/2002	10/8/2002
RAR-BGS-70	9/9/2002	10/16/2002
RAR-BGS-71	9/9/2002	11/13/2002
RAR-BGS-72	9/9/2002	10/3/2002
RAR-BGS-73	9/9/2002	11/14/2002
RAR-BGS-74	9/14/2002	11/15/2002
RAR-BGS-75	9/14/2002	11/7/2002
RAR-BGS-76	9/14/2002	11/7/2002
RAR-BGS-77	9/14/2002	10/20/2002

Question	Asked	Replied
RAR-BGS-78	9/14/2002	11/7/2002
RAR-BGS-79	9/14/2002	10/21/2002
RAR-BGS-80	9/14/2002	11/14/2002
RAR-BGS-81	9/14/2002	11/14/2002
RAR-BGS-82	9/14/2002	11/14/2002
RAR-BGS-83	9/14/2002	10/8/2002
RAR-BGS-84	9/14/2002	11/7/2002
RAR-BGS-85	9/14/2002	11/4/2002
RAR-BGS-86	9/14/2002	11/13/2002
RAR-BGS-87	9/14/2002	10/8/2002
RAR-BGS-88	9/14/2002	10/21/2002
RAR-BGS-89	9/14/2002	10.30.2002, retransmitted 11/15/2002
RAR-BGS-90	9/14/2002	10/21/2002
RAR-BGS-91	9/14/2002	10/21/2002
RAR-BGS-92	9/14/2002	11/14/2002
RAR-BGS-93	9/14/2002	10/21/2002
RAR-BGS-94	9/14/2002	10/21/2002
RAR-BGS-95	9/14/2002	11/7/2002
RAR-BGS-96	9/14/2002	10/10/2002
RAR-BGS-97	9/14/2002	11/14/2002
RAR-BGS-98	9/14/2002	10/12/2002
RAR-BGS-99	9/14/2002	11/13/2002
RAR-BGS-100	9/14/2002	10/10/2002
RAR-BGS-101	9/14/2002	11/13/2002
RAR-BGS-102	9/14/2002	11/13/2002
RAR-BGS-103	9/14/2002	10/21/2002
RAR-BGS-104	9/14/2002	10/21/2002
RAR-BGS-105	9/14/2002	10/21/2002
RAR-BGS-106	9/14/2002	10/21/2002
RAR-BGS-107	9/14/2002	11/14/2002
RAR-BGS-108	9/14/2002	11/14/2002
RAR-BGS-109	9/14/2002	11/14/2002
RAR-BGS-110	9/14/2002	10/3/2002
RAR-BGS-111	9/14/2002	10/3/2002
RAR-BGS-112	9/14/2002	10/3/2002
RAR-BGS-113	9/14/2002	10/21/2002
RAR-BGS-114	9/14/2002	10/14/2002
RAR-BGS-115	9/14/2002	11/14/2002
RAR-BGS-116	9/14/2002	10/21/2002
RAR-BGS-117	9/14/2002	10/16/2002
RAR-BGS-118	9/14/2002	10/10/2002
RAR-BGS-119	9/14/2002	10/21/2002
RAR-BGS-120	9/14/2002	10/14/2002
RAR-BGS-121	9/14/2002	10/21/2002; Supplemental 11/13/2002
RAR-BGS-122	9/14/2002	10/21/2002
RAR-BGS-123	9/14/2002	10/21/2002
RAR-BGS-124	9/14/2002	10/14/2002
RAR-BGS-125	9/14/2002	11/14/2002
RAR-BGS-126	9/14/2002	10/21/2002
RAR-BGS-127	9/14/2002	10/16/2002
RAR-BGS-128	10/23/2002	11/13/2002
RAR-BGS-129	10/23/2002	11/7/2002
RAR-BGS-130	10/23/2002	11/13/2002
RAR-BGS-131	10/23/2002	11/8/1001
RAR-BGS-132	10/23/2002	11/14/2002; Supplemental 11/25/2002
RAR-BGS-133	10/23/2002	11/8/1001
RAR-BGS-134	10/23/2002	10/20/2002
RAR-BGS-135	10/23/2002	11/4/2002; Supplemental 11/27/2002
RAR-BGS-136	11/14/2002	
RAR-BGS-137	11/14/2002	
RAR-BGS-138	11/14/2002	11/26/2002
RAR-BGS-139	11/14/2002	
RAR-BGS-140	11/14/2002	11/26/2002
RAR-BGS-141	11/14/2002	11/27/2002
RAR-BGS-142	11/14/2002	11/27/2002
RAR-BGS-143	11/14/2002	
RAR-BGS-144	11/14/2002	
RAR-BGS-145	11/14/2002	
RAR-BGS-146	11/14/2002	
RAR-BGS-147	11/14/2002	
RAR-BGS-148	11/14/2002	
RAR-BGS-149	11/14/2002	11/26/2002

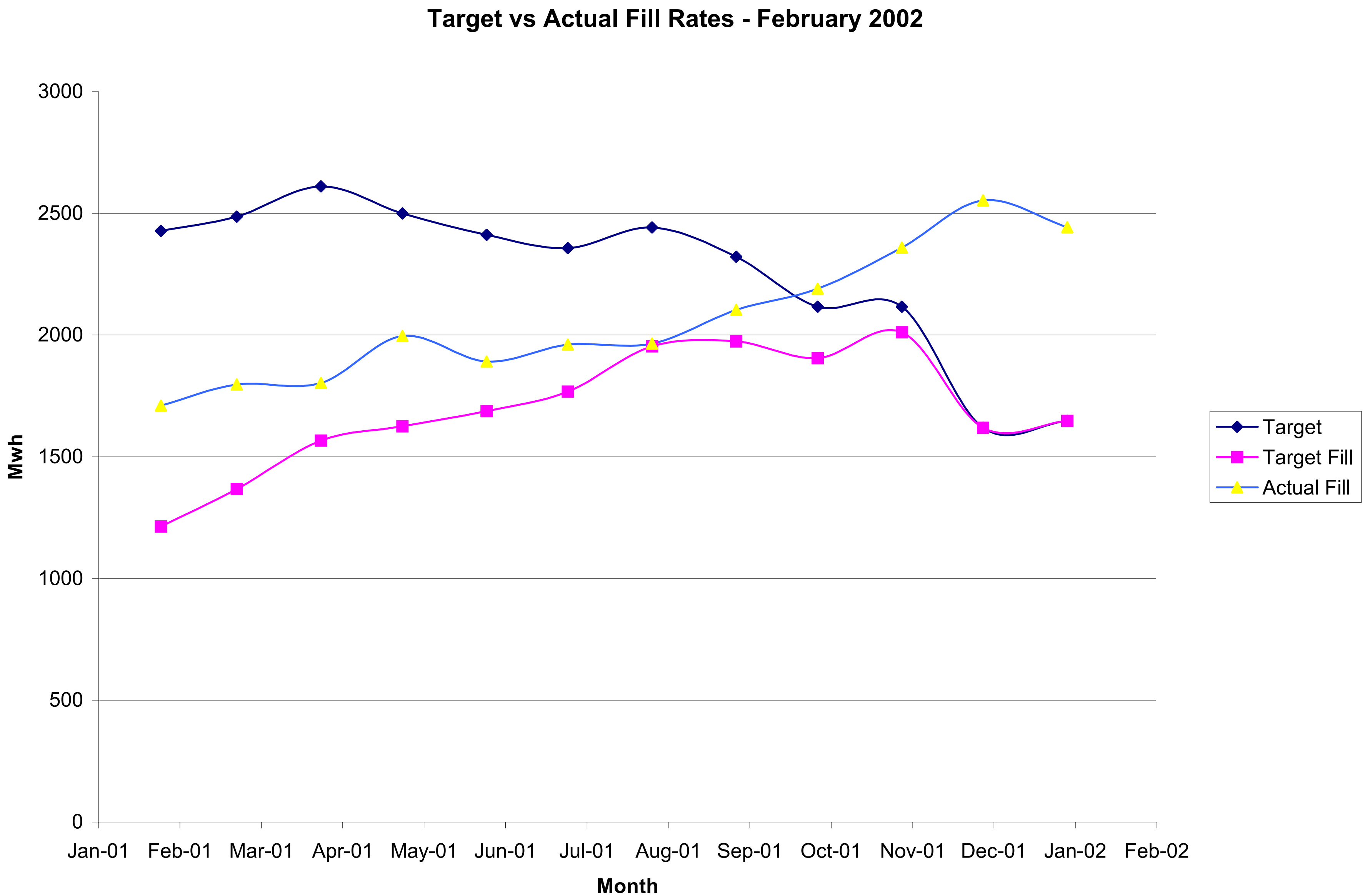
Schedule PLC-4:
Target vs. Actual Fill Rates



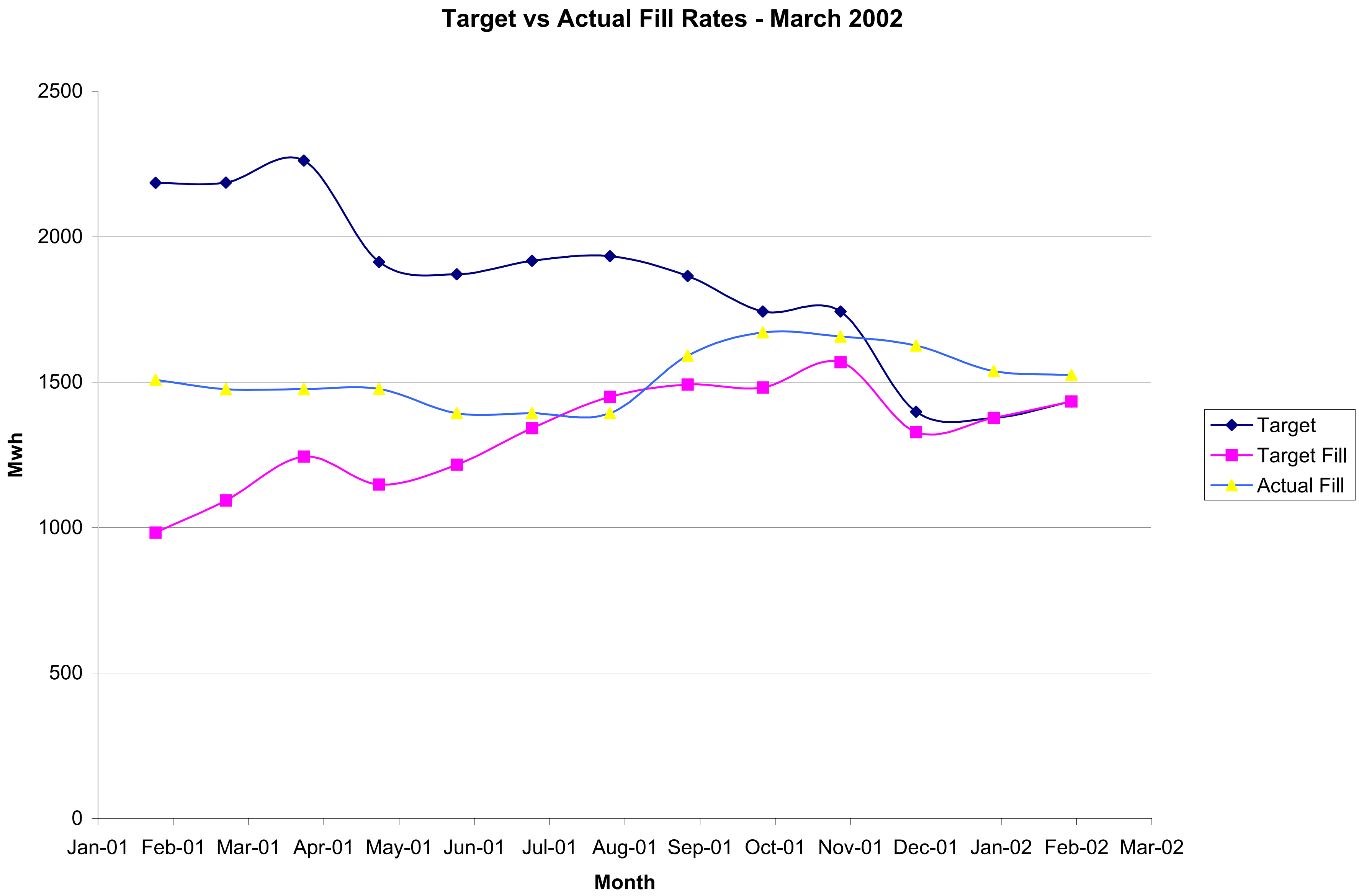
Schedule PLC-4:
Target vs. Actual Fill Rates



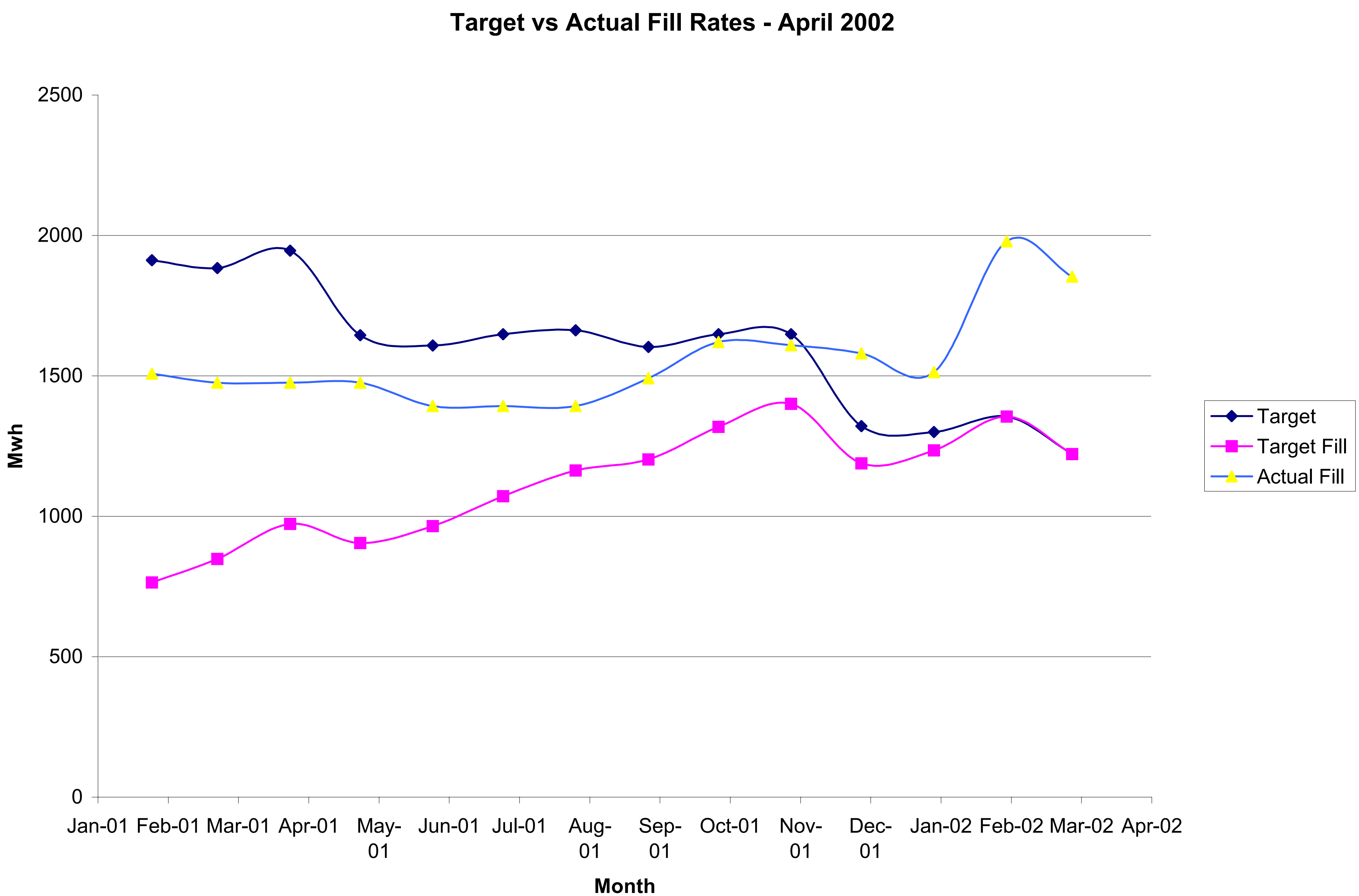
Schedule PLC-4:
Target vs. Actual Fill Rates



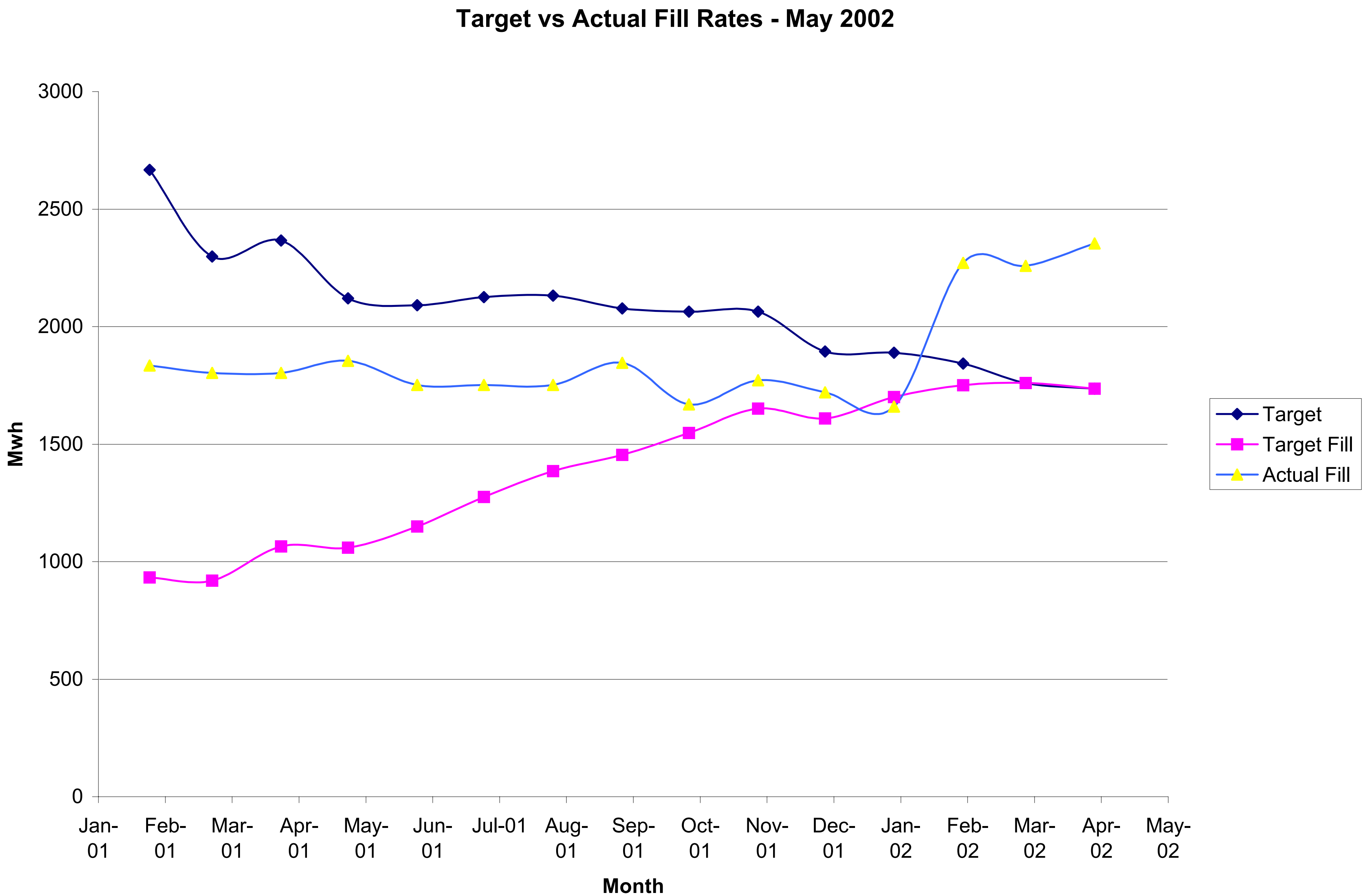
Schedule PLC-4:
Target vs. Actual Fill Rates



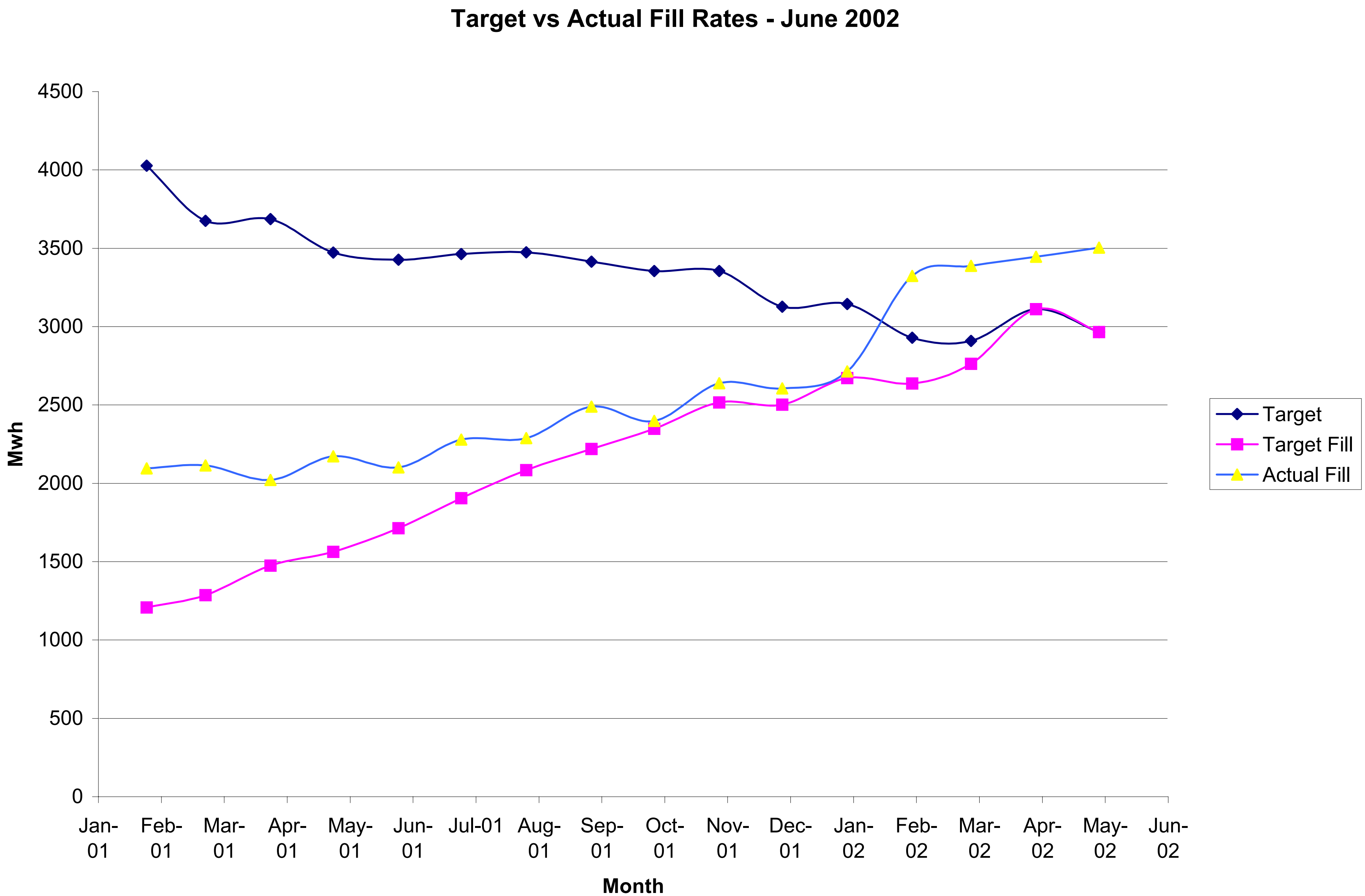
Schedule PLC-4:
Target vs. Actual Fill Rates



Schedule PLC-4:
Target vs. Actual Fill Rates



Schedule PLC-4:
Target vs. Actual Fill Rates



Schedule PLC-4:
Target vs. Actual Fill Rates