STATE OF CONNECTICUT

BEFORE THE DEPARTMENT OF PUBLIC UTILITY CONTROL

Petitions of the Office of the	**)**	
Attorney General and Office	**)**	
Consumer Counsel For an	**)**	
Investigation of Overearnings	**)**	Docket No. 00-12-01
By The Connecticut Light	**)**	
And Power Company	**)**	

and

DPUC Determination of CL&P	**)**	
Standard Offer	**)**	Docket No. 99-03-36 RE03

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE OFFICE OF CONSUMER COUNSEL

Resource Insight, Inc.

MARCH 1, 2001

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I. Identification and Qualifications

Q: State your name, occupation and business address.

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

Q: Summarize your professional education and experience.

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

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters. My work has considered, among other things, the cost-effectiveness of prospective new generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking (PBR). My resume is appended to this testimony as Exhibit PLC-1.

Q: Have you testified previously in utility proceedings?

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

Q: Have you testified previously before this Commission?

A: Yes. I testified in

- Docket No. 83-03-01, a United Illuminating (UI) rate case, on behalf of the Office of Consumer Counsel, on Seabrook costs.

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

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

A: Yes. I am the author of a number of publications on rate design, cost allocation, power-plant cost recovery, conservation-program design and cost-benefit analysis, and other ratemaking issues. Several of my recent papers deal with issues in industry restructuring, including integrated resource planning, environmental considerations, and stranded-cost determination. These publications are listed in my resume.

II. Introduction

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Connecticut Office of Consumer Counsel.

Q: What is the purpose of your testimony?

A: I was asked to address some issues related to the possible revision of the Generation Services Charge (GSC) in the rates of Connecticut Light and Power. The issues I consider include the following:

- What would be the effect of an increase of the GSC on the recovery of stranded costs through the Competitive Transition Charge (CTA), and on total costs to CL&P ratepayers?
- Would increasing the GSC now, while GSC energy is supplied under fixed-price contracts, ease the transition to new rates and increased competition at the beginning of 2004, when the contracts expire?
- Is Connecticut facing a restructuring debacle comparable to that in California?

Q: What are your conclusions on these questions?

A: Increasing the Generation Services Charge now, if it has any effect at all, would be likely to reduce CTA revenues and leave additional stranded costs to be collected after 2003. Any customers who choose to purchase power from another supplier due to an increase in the GSC will almost certainly be purchasing power at prices well above the price the Company pays for GSC power. This will increase the total cost paid by CL&P's ratepayers as a whole. Those increased costs would result in collection of less stranded costs during the current rate freeze, and of more stranded costs—via higher rates—after 2003.

Increasing the GSC now would make the post-2003 transition more difficult. It is likely that the Company's actual cost of power for the GSC will increase in 2004, compared to the current contracts. The Company's distribution and transmission costs may also increase. The only cost component that is likely to be subject to a large decrease in 2004 to offset these increases would be the Competitive Transition Charge. But if stranded-cost recovery has been reduced due to a premature increase in the GSC, the Department's ability to reduce the CTA in 2004 may be constrained.

Connecticut does not face the structural problems that have pushed California's major utilities to the brink of bankruptcy. New England power prices may rise or fall over the next few years, but the extreme prices experienced in California are highly unlikely. The Department can continue to protect both CL&P and its ratepayers from price spikes, such as those experienced in California, by directing electric distribution utilities, including CL&P, to purchase future GSC service under multi-year contracts.

III. The Generation Services Charge, the Competitive Transition Charge, and Stranded Costs

Q: What is the current relationship between the Company's GSC, CTA, and recovery of stranded costs?

A: Public Act 98-28 required a 10% reduction in CL&P's rates, and provided for specific components of the rates to be allocated to conservation, renewables, the System Benefits Charge, distribution, and transmission. The remainder of the rates comprises the GSC and the CTA. The GSC pays for the cost of power CL&P acquires for its customers who choose not to purchase power elsewhere; the CTA pays continuing above-market costs and contributes to paying down previously incurred balances. Service under the GSC is also referred to as standard-offer service. The CTA was set as a residual after the GSC and all other costs were subtracted from the total rate.

In Docket No. 99-09-36, the Department approved the Company's purchase of power from three suppliers to serve the standard offer at an average price of about $44.6/MWh, but increased the retail GSC charge by an average of $2.6/MWh to help encourage customers to switch to alternate generation suppliers.[1] This retail adder was to be treated as part of the Competitive Transition Charge; for customers who stayed with CL&P's standard offer service, the contribution towards stranded costs would be the same as if the GSC was set at cost. As a result, while switching customers contribute the reduced CTA towards stranded costs, standard offer customers pay the CTA, plus the $2.6/MWh.

Q: What would be the effect now of increasing the Generation Services Charge?

A: All else held equal, the immediate effect is that the Competitive Transition Charge would have to be reduced, but the increased retail adder would result in additional GSC over-collections, which would be assigned to the CTA. If all customers were on standard-offer service, and none switched to an alternative supplier, the increase in the GSC rate would have no effect on anything other than the appearance of tariffs and bills.[2]

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[1]These values are from the spreadsheet embedded in page 4 of the electronic version of the December 15, 1999 order in Docket No. 99-03-36. Late-filed Exhibit 4 indicates an average GSC rate of 4.81¢/kWh, which may reflect a different weighting between classes.

[2]For example, the small increase in the GSC proposed in the example in LFE-4, if spread evenly over rate classes, would not be likely to induce much additional switching from the standard offer.

Problems arise because some customers are not on standard-offer service, and because others may leave standard-offer service if the GSC is raised enough.[3] There are two such problems.

First, every dollar shifted from the CTA to the GSC for a customer who is not on standard-offer service is a dollar less of stranded costs that will be recovered. The higher stranded-cost recovery is now, the lower it can be after 2003 (I will return to this issue in the next section) and the sooner the CTA can be phased out. For customers who already use alternate suppliers, the shift from CTA to GSC would be a rate decrease, allowing them to escape some of their share of recovery of stranded costs. Other customers will wind up paying more in stranded costs due to this shift in rate design, with standard-offer customers effectively subsidizing the others.

For a customer who switches to an alternative supplier due to the increase in the GSC, the shift of revenues from CTA to GSC similarly reduces the recovery of stranded costs, but some of the subsidy from customers who remain on the standard offer will flow to the supplier, rather than the customer. This situation is even worse for customers who have already switched.

Second, any additional switching that occurs as a result of the shift in revenues from CTA to GSC will increase the total costs of electricity supply for Connecticut ratepayers. As shown in Exhibit PLC-2, market energy prices are now much greater than they were when the GSC supply contracts were signed in October 1999. Were the Generation Services Charge some-

[3]The problem lies not in customers switching, which was one of the goals of restructuring, but in their switching in the specific circumstances of low-price standard offer supply and high market prices.

how increased enough to make switching attractive, the Company would be avoiding energy priced at 4.5¢/kWh, and customers would be replacing it with energy priced at 5.5¢/kWh, 6.5¢/kWh or more.[4]

Q: Is there any benefit to societal welfare from replacing the less expensive energy with more expensive energy?

A: No. Due to the rate structure, the increase in total cost would not even provide more realistic price signals, since the customers who switch suppliers would see a decrease in their rates at a time of high market prices. In later years, when market prices are likely to be lower, rates will have to be raised to recover the under-collected stranded costs.

The transfer of ratepayer load from CL&P's below-market contracts to market-based purchases would only benefit CL&P's three suppliers.

It is difficult to see any policy purpose in increasing total costs to ratepayers, reducing collection of stranded costs, and forcing customers who remain on the standard offer to subsidize those who can switch.

IV. Effects of a Generation Services Charge Increase on the 2004 Transition

Q: Would an increase in the GSC today ease the transition at the end of the current standard-offer contracts?

A: No. If anything, it would make the problem worse.

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[4]If the Company could resell the unused standard offer supply on the market, there would be no loss. But CL&P has no entitlement to any specific amount of power; as customers switch, the suppliers deliver less of the discounted power. Connecticut consumers simply lose the low-cost power that the Department providently arranged for them in 1999.

At this point, the market appears to be anticipating that market prices in 2004 will be higher than they were in 1999; see Exhibit PLC-2. If the current forward contract prices remain unchanged, new contracts by the Company for standard offer service, and for direct purchases by consumers from suppliers, might cost about 1¢/kWh more in 2004 than 1999.[5]

If the Generation Services Charge needs to be increased for 2004, it would be desirable to be able to decrease some other component of the rate. It is not clear whether distribution and transmission rates can be decreased substantially at that time. So the best hope for moderating any rate increase in 2004 would be to decrease the Competitive Transition Charge.

To the extent that a reduction in the CTA in 2001 would reduce the rate at which stranded costs are amortized, the Department's ability to reduce the CTA in 2004 would be more limited. Thus, a rate design change in 2001, shifting revenues from the CTA to the GSC, would provide no benefit for most ratepayers in 2001–2003, and would make them worse off in 2004, when they are likely to need some rate relief.

Q: Would an increase in the Generation Service Charge now reduce rate shock in 2004?

A: No, unless the Department were to raise total rates above the level in 2000. So long as the total rate level for each class is fixed for 2001–2003, under the terms of the restructuring act, and assuming that costs will rise in 2004 due to higher generation prices, rates will rise in 2004. Shifting revenues from the

[5]The differential depends in part on what the suppliers of the existing 1999 contracts were expecting in terms of prices for 2000–2003.

CTA to the GSC for 2001–2003 will not reduce the increase to 2004, and may raise it, as I discuss above.

Q: Does the current disparity between the Generation Service Charge and market price of power create any problems in 2004?

A: Not for the Company and its customers. The standard offer power costs CL&P 4.5¢/kWh, regardless of what it might be worth in the market.

The three standard-offer suppliers—Select Energy (a CL&P affiliate), Duke Energy Trading, and NRG Power Marketing—would probably prefer that CL&P customers leave standard-offer service, so that less of their resources will go to those relatively low-priced sales and more to the higher-price market sales. That is not to say that serving the standard offer is hurting them. All three of these entities are large and sophisticated enough to make sure that they have adequate supplies of power, non-fossil generation, and/or fossil fuels at essentially fixed prices to serve these fixed-price contracts. For example:

- Select and Duke have purchased Millstone power through 2001.
- Select and NRG are affiliated with the purchasers of CL&P's hydro and fossil generation, respectively.
- An NRG affiliate owns more than 100 MW of coal-fired capacity in Massachusetts, and thousands of MW of oil and gas capacity in New York.
- The 2000 NEPOOL Capacity, Energy, Load and Transmission Report lists Duke entitlements to about 500 MW of non-utility generation in New England.

Combined with futures contracts for oil and gas, and multi-year purchases from other generators, the three suppliers should have been able to protect themselves from changing prices in the electricity and fuels markets. If they did not take that precaution, it is a problem for their shareholders, not for the Department.

Q: How should the Company prepare for the 2004 transition?

A: The Company should monitor market conditions, and plan to solicit new power supplies in late 2002 or early 2003. Customers should be informed in mid-2003 of the new General-Service-Charge values that will go into effect in January 2004, giving them ample time to shop for alternative suppliers.

In the meantime, CL&P should be doing what it can to decrease the post-2003 stranded costs, so that the Competitive Transition Charge can be reduced as the GSC is increased. If market prices moderate from current contract prices, then a CTA decrease in 2004 may be less important than current projections would suggest.

V. Connecticut and California

Q: Is Connecticut in a position similar to California's electricity crisis, and is it likely to be?

A: No. There are many important differences between California and Connecticut, in ratemaking and in the supply situation.

Q: Please describe the pertinent differences in the ratemaking used in California and Connecticut restructuring.

A: In terms of ratemaking in the restructuring process, California established a generation component in each utility's rates, comparable in some ways to the combination of the Generation Service Charge and Competitive Transition Charge in Connecticut's rates. Each California utility was expected to pay the market costs of power supply for its standard-offer service, and have enough generation revenue left over to pay off its stranded costs before the end of the transition period. For a number of reasons, parties were very concerned about the market power of the California utilities. Among these concerns were the absence of any established power-pooling arrangement, the high concentration of load and generation in just two utilities, and the fact that the utilities were allowed to retain ownership of most of their generation.[6] As a result, the utilities were required to purchase power for their standard-offer service from the spot market, without long-term contracts.

The California utilities wound up selling more of their capacity than had originally been envisioned. When market prices rose, they were purchasing large amounts of their power from the spot market, and had total costs of power supply for standard-offer service that exceeded their entire generation charge. Under the rules of the California restructuring process, the utilities were not allowed to raise their rates until they had paid off their stranded costs, and soon faced enormous losses.[7]

In contrast, the Connecticut utilities are serving their standard offer service with multi-year contracts. The Department should continue this practice past the expiration of the current contracts in 2003. If the cost of standard offer supply rises when the current contracts expire, the Department has the authority to raise rates, if necessary.

Q: What are the differences in the supply situation?

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[6]In contrast, New England has operated under joint dispatch and at least partly joint planning for a quarter century.

[7]The exception to this problem is San Diego Gas and Electric, which had paid off its stranded costs and was no longer under the rate cap when market prices rose sharply.

A: The structure of the California ISO, such as its inability to dispatch plants on a cost basis, may make it easier for generators to exercise market power there than in ISO–New England. While prices are also inflated above competitive levels in New England, the problem has not been nearly so bad as in California.

More fundamentally, the California supply situation has been very tight. Perhaps due to the uncertainty about the extent of market power that would be exercised by the incumbent utilities, few developers proposed new plants until fairly recently. In New England, on the other hand, a enormous number of new plants have been proposed, many are under construction, and some have already entered service. The following table, from a report to the ISO, summarizes a recent view of the capacity additions the ISO expects over he next few years, for reference and high-demand cases.[8]

Summary of Capacity Additions through 2005

(As of 3rd quarter, 2000)

	Reference Case		***High Case***	
Status	***Summer (MW)***	***Winter (MW)***	***Summer (MW)***	***Winter (MW)***
Operational	*1,459*	*1,666*	*1,459*	*1,666*
Under Construction	4,923	5,885	4,923	5,885
Permits Complete	0	0	3,358	4,028
Total	**6,382**	**7,551**	**9,740**	**11,579**

California has also been plagued by gas-supply problems, which have pushed prices over $40/MMBtu on some days this winter, while even the peak gas prices in New England have barely reached $10/MMBtu when the Henry Hub price was over $8.50/MMBtu. The relatively small differentials between the gas-exporting Gulf Coast region and New England suggests that

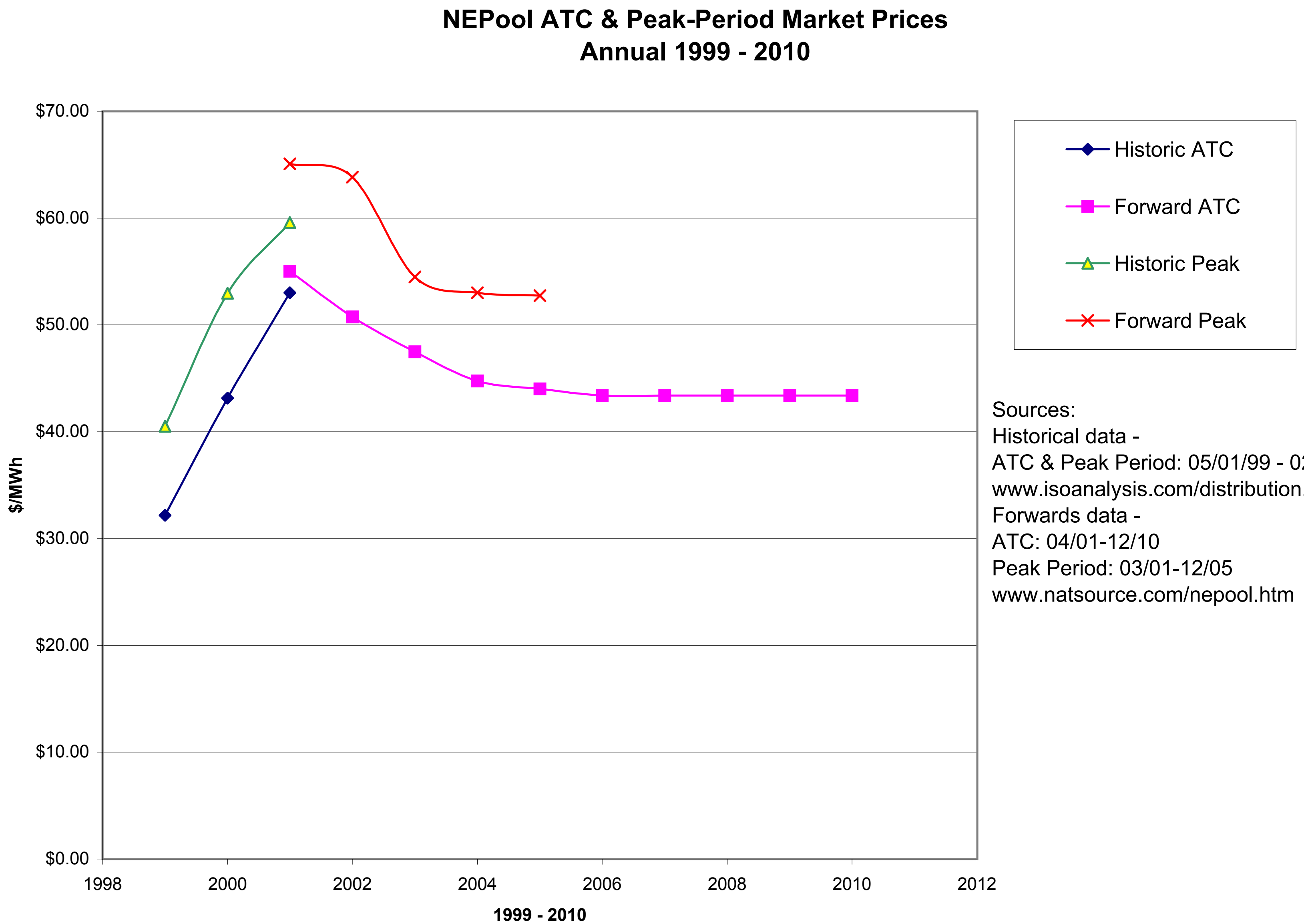
[8] "Steady-State Analysis of New England's Interstate Pipeline Delivery Capability, 2001–Levitan Associates, ISO New England, January 29, 2001

there were no serious transportation problems for New England, which receives gas from the Gulf, as well as from western Canada, and the new Maritimes pipeline from eastern Canada. With the rise in gas-fired generation in New England, ISO–New England has identified the possibility of gas-supply constraints as early as 2003, but that problem should be controllable with additional gas pipelines and storage, and provisions for alternative fuels at gas-fired combined-cycle units, such as distillate and propane.[9] Most importantly, the ISO is preparing to avoid potential problems two years in advance, rather than assuming that market forces will avoid all problems.

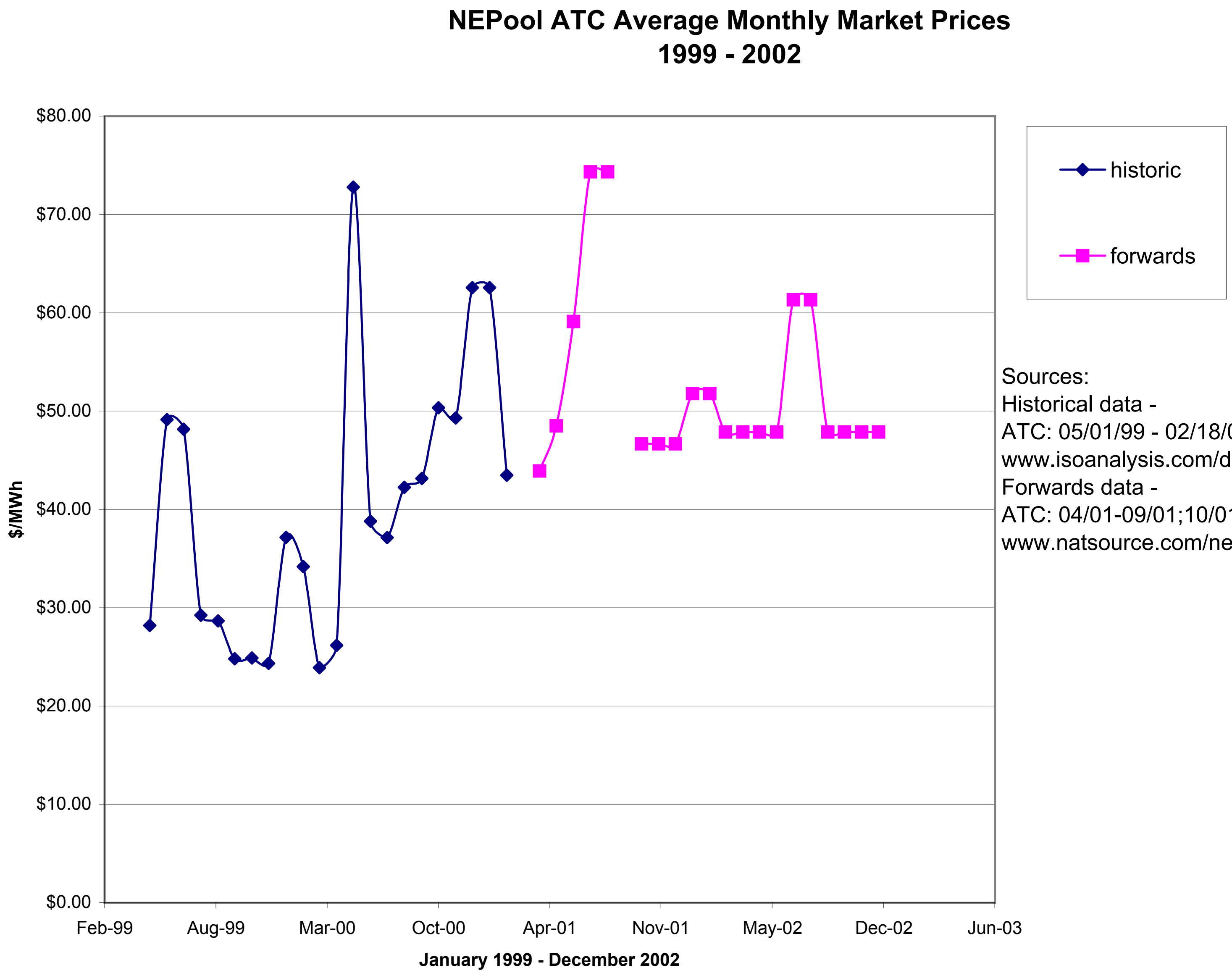
Q: Does this conclude your testimony?

A: Yes.

[9]Op. cit.



Sources:
Historical data -
ATC & Peak Period: 05/01/99 - 02/18/01
www.isoanalysis.com/distribution.htm
Forwards data -
ATC: 04/01-12/10
Peak Period: 03/01-12/05
www.natsource.com/nepool.htm



Sources:
Historical data -
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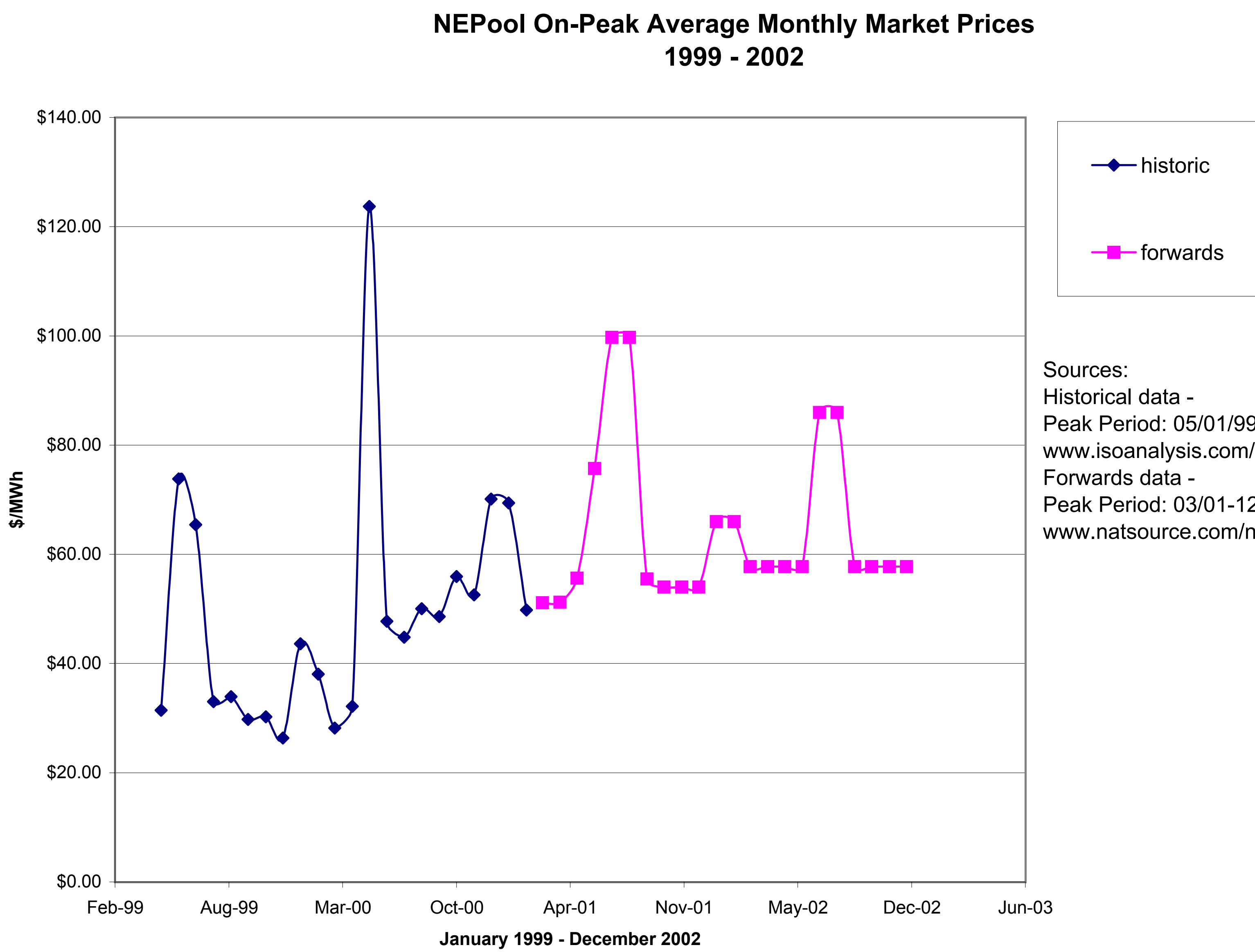

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