Horizontal Market Power in New England Electricity Markets: Simulation Results and a Review of NEPOOL's Analysis

Prepared for the

New England Conference of Public Utility Commissioners

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1. INTRODUCTION AND SUMMARY

This report describes simulation analysis of horizontal market power in New England. While the simulation is not elaborately detailed, it does represent the key features of the electricity market in New England: generation capacity by owner, interties, fuel prices, plant outages, and hourly loads. It is sufficiently detailed to support the main conclusion – that market power in electricity generation is a serious concern, even before transmission constraints within the region are considered.

Moreover, of the analyses of electric market power in New England that have been done to date (Gilbert, 1996; Hartman and Tabors, 1996; Hieronymus, 1997), this is the only one that goes beyond consideration of market concentration measures (e.g., HHI) to examine through simulation modeling techniques the opportunities for large companies to elevate prices above competitive levels. We welcome questions, comments and criticism of this work, and hope that it is a helpful contribution to the discussion of market power in the region.

We begin with a short introduction to market concentration and market power, and summarize Leonard Weiss' analysis linking the two across a broad range of industries. Then, we calculate market concentration measures for electric generation in New England, and compare these with the ranges of the Department of Justice's guidelines, showing NEPOOL to be "highly concentrated."

We then comment upon other studies of market power in New England, focusing mainly upon the analysis conducted by Dr. Hieronymus of Putnam, Hayes, and Bartlett, Inc. for NEPOOL (Hieronymus, 1997). While that analysis is a good start, in that the critical data were collected and loaded into dispatch simulation model and the measures of concentration were calculated, we conclude that the analysis is inadequate. The main shortcoming is not any particular error in the analysis, but rather that it did not even attempt to address issues of tight capacity situations and strategic behavior by market participants. Dr. Gilbert's analysis of market power in New England (Gilbert, 1996) is similarly limited to calculations of measures of market concentration, in this case without the use of a dispatch simulation model. Drs. Hartman and Tabors go a step further in that they actually examine the shape of the supply curve and then bin generators by marginal cost (Hartman and Tabors, 1996). However, they stop short of actually looking in a quantitative way at whether withholding capacity or bidding above variable cost will be profitable.

Our own analysis of market power in New England electric generating markets looks specifically and quantitatively at the ability of the larger companies to elevate the price of electricity above competitive levels. We find that for the largest supplier (Northeast Utilities) an optimal pricing strategy is to bid significantly above marginal cost. Specifically, in the base case NU can increase its net operating revenue by about 10 percent by bidding optimally at levels above marginal cost. The estimated impact upon consumers over the course of a year amounts to $387 million in costs above what would prevail if all suppliers bid competitively. The other large companies (New England Power, Boston Edison Company, and Central Maine Power) do not have as large a market share as NU, and hence it is not surprising that they have correspondingly less ability to profitably elevate prices. A scenario in which the large suppliers simultaneously optimize their pricing strategies (without colluding) yields a market power result that is a bit worse for customers than the case with NU as the market leader.

A series of scenarios and sensitivity cases illustrate that the specific results are sensitive to the input assumptions such as plant outages and purchased power. In general, the tighter the capacity situation due to plant outages, higher demands, or lower intertie assumptions, the greater the potential to exploit market power.

At the same time, the main conclusion – that market power is quite a serious problem in this market – is robust.

Requiring fixed bids shows some promise as a mitigation policy, particularly if the bids are fixed for longer periods (e.g., a week). There are also important mitigating factors to market power, including market entrants (imports or new facilities), demand elasticity, and antitrust regulation. Nonetheless, we remain concerned that abuse of market power in generation may become common and significant, both in local load pockets (perhaps created intentionally by market participants) and broadly in the regional market. Further studies are needed, in which strategic behavior is analyzed in the context of real markets with generation ownership patterns, transmission constraints, and opportunities for new entrants.

The Vermont Department of Public Service funded the initial work on this analysis. It was completed with financial support from the New England Conference of Public Utility Commissioners. The section discussing the analysis of Hartman and Tabors was prepared jointly with Paul Chernick of Resource Insight, Inc. as part of a project for the New Hampshire Office of Consumer Advocate (Synapse, 1997).

2. HORIZONTAL MARKET POWER IN ELECTRICITY GENERATION

2.1. Market concentration and oligopoly pricing.

An oligopoly is a market structure in which a few firms dominate the supply of a commodity. Its occurrence is quite common. What economic theory tells us about pricing in oligopolistic markets is that prices can be expected to fall between the extremes of a perfectly competitive market at the low end and an unregulated monopoly market at the high end. While various theories provide interesting insights in analyzing real or hypothetical markets, it is impossible to say with confidence how a particular market will behave within the two tractable extremes.

The two most common measures of market concentration are the Herfindahl index, and the "concentration ratio." The Herfindahl is the sum of the squares of individual firm's market shares expressed as percentages. For example, the Herfindahl index would be 1000, for an industry with ten equal size firms. “Concentration ratios” are specified for a particular number of firms. For example, the three firm concentration ratio (abbreviated as “CR3”) for that same industry would be 30 percent. No single metric can capture the complexities of the cost structures and relationships in a real market, but the Herfindahl and concentration ratio are both useful measures that can serve as a starting point in analyses of market power.

Different oligopoly theories point to different measures of concentration as the best for explaining how significantly prices might deviate from marginal costs. Similarly, empirical explorations of concentration and price data in various industries are inconclusive in determining a generally preferred measure of concentration, which can accurately predict pricing behavior and price setting practices. At one theoretical extreme, oligopoly firms may act competitively, or “quasi-competitively,” resulting in reasonable market prices. At the other extreme, the firms may collude perfectly, with the result being much like the prices that would occur with an unregulated monopoly.

In between these extreme cases, there are various theoretical models. Perhaps the simplest of these is the Cournot solution, in which each firm is assumed to treat all of the other firm’s decisions as fixed in determining its own pricing strategy. More complex “conjectural variations” models involve strategic assumptions about how the other firms’ behavior will change. For example, in some markets there may be a “price leader” whose decisions tend to be followed by the other firms. Game theory can be useful in analyzing participant behavior in oligopoly markets, since the opportunities and risks of cooperation (or collusion) resemble the much analyzed “prisoners’ dilemma” situation. (See, for example, Gibbons, 1992.)

Any of these theoretical models may have some insight to offer as to the behavior of a market in electricity generation. However, even for markets that have existed for years and have been studied in detail, there are likely to be differences of opinion about how the market has behaved. It is simply impossible to say with confidence how a complex market will work before it exists, particularly when there are many unresolved aspects of its regulation and structure. The most we can do is to study the current market structure and cost functions, and to identify areas of concern and potential solutions. The results of Robert Alexrod’s simulation tournaments point to the importance of the early stages of market development as a key determinant of market behavior. (See, for example, Scherer and Ross, 1990, 216 to 219.)

2.2. Concentration and price in other industries.

Leonard Weiss (1989) has examined the relationship between market concentration and price in many markets and has found that higher levels of concentration do indeed tend to correlate with higher prices. Weiss's summary of 121 data sets of concentration and price covering a wide range of industries (including airlines, banking, cement and many others) shows a convincing majority of studies in which concentration appears to result in higher market price:

	Number of Data Sets
Significant positive effects	76
Non-significant positive effects	30
Non-significant negative effects	11
Significant negative effects	4
TOTAL	121

With regard to prices, Weiss found that the effects of concentration on price “seem to be minor at levels below CR4 of 50” (page 276), and that the specific relationship varied considerably for the various markets and data sets analyzed.

In electricity markets, there is little evidence so far to provide guidance as to how particular generation markets will function if deregulated. A simple examination of concentration in power pools does suggest, however, that with ownership of generation facilities as currently structured the potential for abuse of market power is a serious possibility.

2.3. Transmission constraints and load pockets

In New York, research has been done to identify “load pockets,” in which local transmission constraints could result in opportunities for abuse of market power, and to develop policy options to address load pockets. A report (NYPSC, 1996) from this process categorizes various types of load pockets and notes that market power within a load pocket could be influenced by utility actions outside of the pocket. Specifically, a company owning generation both inside and outside of the pocket might operate its resources outside of the pocket in a way that minimizes the transmission capability into the pocket, thereby creating opportunities to take advantage of the constraint by charging more for power within the pocket. The City of New York is an especially large and problematic load pocket (Biewald, 1997).

The NEPOOL transmission system may not be as constrained as that of New York. Dr. Hieronymus’ testimony for NEPOOL (1997) finds that in general transmission constraints within NEPOOL are not a major factor in market power, but recognizes that transmission constraints intentionally created by generators could be an important problem.

Specific research focusing on NEPOOL’s transmission system and the opportunities for suppliers to create and/or take advantage of load pockets is needed. Such analysis will be critical in determining appropriate directions for structuring the New England generation market.

2.4. Market Entry

The entry of new suppliers into a regional market -- either through the provision of existing generation from outside the region over transmission ties or through the construction of new facilities within the region -- is a crucial factor in limiting the ability of a dominant supplier to abuse market power. Entry into the generation market in New England is from some perspectives open, and could be made increasingly so. However, constraints related to transmission capability, power plant construction lead time, the availability of suitable sites for new plants and environmental permitting for new facilities could all be important factors resulting in effective barriers to entry.

3. CONCENTRATION OF OWNERSHIP OF ELECTRICITY GENERATION IN NEW ENGLAND

Market power arises, in part, due to concentration and market dominance. Based upon current ownership, the capacity shares of the five largest companies in NEPOOL are as follows:

Northeast Utilities	35%
New England Electric System	20%
Boston Edison Company	13%
Central Maine Power	7%
United Illuminating	5%

Thus, the concentration ratio for the three largest companies (CR3) is about 68 percent, and the concentration ratio for the five largest companies (CR5) is 80 percent. The Herfindahl (or "HHI") index is about 1950. Department of Justice guidelines for evaluating mergers indicate that at a Herfindahl above 1800 the market is "highly concentrated" and adverse effects are "presumed." In such concentrated markets, there are significant concerns of market power, although whether and to what extent there is a problem depends upon a variety of other factors, for example, barriers to market entry (Department of Justice and Federal Trade Commission, 1992). These guidelines have been incorporated into FERC policy on mergers (FERC, 1997).

The New York Power Pool has similar levels of concentration of ownership of generating capacity. Analysis of market power in New York, found that the largest firm at a market share of 30% could "essentially dictate the market price." For example, by following a simple bidding strategy at double its variable costs, a firm would increase the pool's average clearing price from $29/MWh to

$40/MWh, dramatically increasing its profits, as well as the profits of other smaller companies (Falkenberg, 1995).

Our analysis of the New England electricity market indicates that there is opportunity for abuse of market power in generation if restructuring moves forward, given current cost and ownership conditions. Specifically, there are opportunities for the large firms to exercise “unilateral market power,” as in the New York example noted above. That is, even with all of the other firms offering their generation at variable cost, one large company can increase its net gain by selling less output, because of the resulting increase in the market price. With only two firms acting collusively the effect can be dramatic. These opportunities are particularly pronounced in situations where capacity is tight, for example in hours with high levels of demand or multiple large unit forced or scheduled outages. This analysis is described later in this report.

One of the factors that may cause market power to be a problem in electricity markets, even at lower levels of concentration, is the difficulty of storing electricity. That is, because the supply of and demand for electricity must balance over very short time intervals, there may be short-run opportunities for companies to take advantage of shortages in a way that cannot occur if other suppliers or purchasers can readily and inexpensively store some inventory of the product. The fact that there are some storage technologies for electricity may help the overall situation somewhat, but confer a strategic advantage upon the owners of the storage capability. In addition to the electricity storage of conventional hydroelectric facilities, New England has 1682 MW of pumped storage hydro capacity, 7 percent of the total generating capacity in the region (NERC, 1996). This pumped storage capability is controlled primarily by the two largest utility systems in the region, Northeast Utilities and New England Electric, adding to the opportunity for these companies to control market prices.

4. A BRIEF REVIEW OF ANALYSES OF MARKET POWER IN NEPOOL

4.1. NEPOOL's analysis of market power

We find little comfort in the analysis of market power in New England electricity markets presented by William Hieronymus in his Testimony of February 28, 1997 in FERC Docket Nos. OA97-237-000 and ER97-1029-000. A more detailed review of Dr. Hieronymus' analysis has been done for NECPUC (Rosen, Duckworth, and Biewald, 1997). Here, we will touch briefly on several major areas of concern. Specifically, these are (1) the tone of the presentation, (2) the lack of analysis of tight capacity situations, and (3) the focus upon measures of concentration to the exclusion of examination of opportunities for strategic behavior.

4.1.1. Tone and objectivity

The draft testimony reads as an argument advocating for market pricing in NEPOOL. We would find more comfort in an objective, balanced discussion of the issues. Frankly, the tone of the presentation raises concerns about the study's objectivity, and NEPOOL's role in contracting and managing the analysis.

4.1.2. Tight capacity situations

The analysis does not consider situations in which the market is tight, even though these conditions are exactly when abuse of market power is likely to be possible.

The conclusions of the analysis are reported for the "study period." For example:

> "Throughout the study period, the market for installed capability will clear even if the largest supplier withdraws completely from the market." (page 28)

and

> " For those few products and time periods [in NEPOOL] where market structure is more highly concentrated, the significant excess capacity that likely will exist means that the markets will be workably competitive since at most a fraction of the supplies available from the larger participants will be required to meet demand. Based on this analysis of market structure, I conclude that the NEPOOL wholesale markets will be workably competitive..." (page 3)

If the study period were the ten or twenty year time frame common for electric utility planning studies, these conclusions might be comforting. However, the study period for Dr. Hieronymus' study seems to be limited to two and one half years -- July 1997 to December 1999 (see pages 17 and 30). The analysts have limited the time frame to the current surplus capacity situation, ignoring future conditions in which NEPOOL could be in a tight capacity situation. Indeed, even a market power analysis for a balanced situation would be interesting. Siting constraints and lead time requirements for new generating capacity make analysis of tight capacity situations essential to an assessment of market power.

Moreover, tight capacity situations can and will be created temporarily due to power plant outages. The methodology of Dr. Hieronymus' study glosses over this important issue by considering outages on only a probabilistic basis.

Our own preliminary analyses of market power indicate that multiple forced generating unit outages and tight capacity situations are the key variables in determining whether and to what extent there is market power for a particular system. Load growth and generator outages, particularly nuclear plant shutdowns, should be incorporated into analysis of market power. The current nuclear outages in New England should have made this need obvious.

4.1.3. Measures of concentration as opposed to opportunities for strategic behavior

Dr. Hieronymus discusses the limitations of measures of market concentration (e.g., the Herfindahl index) at several points in his draft testimony, but then goes on to conduct his analysis of the electricity markets almost entirely in terms of such indices. The analysis of energy markets is done in two steps: first Dr. Hieronymus calculates each company's market share and the overall Herfindahl index for the year (or in the case of 1997 the half-year), then he calculates the same measures for selected conditions such as peak and off-peak hours (see pages 30 to 33). These rule-of-thumb measures only address the extent of concentration in the market -- they do not address the extent of opportunities to abuse market power in particular circumstances.

We would expect that even an inexpensive, quickly conducted study of market power in NEPOOL would explicitly consider the opportunities for suppliers to increase profits through strategic behavior such as raising bid prices and withholding capacity from the market at particular times. While Dr. Hieronymus mentions -- and dismisses -- such behavior, his study does nothing to address it quantitatively. With his simulation model loaded with NEPOOL supply data, we think some quantitative exploration of strategic behavior would be warranted.

In his testimony in the Primergy merger case Dr. Hieronymus speaks to the strengths of modeling behavior "directly" in addition to looking only at measures of market concentration:

> Structural tests are commonly used in market power studies and have value, but it is important to remember that their value derives from the ability of structural metrics (for example, measures of market share) to predict Primergy's success in using certain behaviors – for example, withdrawing capacity or increasing the prices it offers in the economy market – to raise prices above competitive levels. It is preferable, if possible, to analyze the effects of these behaviors directly. Structural tests are used in market power studies principally because of the difficulty of analyzing the potential success of such behaviors directly. (page 53, Hieronymus, 1996)

Dr. Hieronymus' analysis in that case was, in fact, a modeling analysis designed to be a "direct test of the potential to raise prices above competitive levels" (page 53). We believe that a similar modeling analysis can and should be done for NEPOOL.

Also, as we pointed out previously, the large amount of pumped storage hydro capacity in New England, owned by the largest generation owners, presents special opportunities for anti-competitive behavior. These concerns are not mentioned in the market power study. We would expect them to be discussed and analyzed. The implications of the proposed new self-scheduling provisions of the restructured NEPOOL Agreement should also be examined as they may create opportunities to exercise market power.

4.2. Massachusetts Electric's analysis of market power in New England

Dr. Richard Gilbert prepared testimony on market power for Massachusetts Electric (Gilbert, 1996). That analysis, like the NEPOOL analysis discussed above, focused on the level of concentration in the electricity market, primarily be calculating HHIs for capacity (Exhibits RJG-6 and RJG-7). Dr. Gilbert finds that the HHIs for generating capacity in New England are 1,921 and 1,887 for the summer and winter, respectively (Exhibit RJG-6). With additional interties from New York and New Brunswick the HHIs decrease to 1,665 and 1,642 for summer and winter (Exhibit RJG-7). Dr. Gilbert concludes that these numbers "clearly lead to the conclusion that the NEPOOL generation market is workably competitive and that deregulation would be in the public interest" (page 27, Gilbert, 1996).

Dr. Gilbert goes on to discuss various factors that influence the extent of market power, including barriers to entry and the ability of generators to collude. There is, however, no direct analysis of the ability of companies in New England to profitably raise prices.

4.3. Hartman and Tabors' analysis of market power in New England

The study of market power that was conducted for the Massachusetts Attorney General by Hartman and Tabors (1997) goes further than the two studies above in that it examined the shape of the supply curve, and put generators into variable cost bins, rather just calculating measures of concentration. This "binning" is not sufficient to evaluate market power, however, in that it does not provide an indication of whether companies will find it profitable to bid above cost by amounts larger than the resolution of the bin (1 mill per kWh, in this case).

While their analysis does not directly consider the profitability of bids that are significantly above variable cost, the cost and capacity data provided by Hartman and Tabors in their Exhibit 16 allow some illustrative calculations. For example, with 84% of capacity available and a load of about 19,000 MW, removing about 500 MW of capacity would increase the market-clearing price from about \$29/MWh to about \$55/MWh. If Northeast Utilities owns 35% of the 19,000 MW of operating capacity, and withdraws 500 MW of that generation, its hourly revenues go from

$$\$29/\text{MWh} \times 6{,}600 \text{ MWh} = \$193{,}000, \text{ to}$$

$$\$55/\text{MWh} \times 6{,}100 \text{ MWh} = \$338{,}000,$$

while saving about \$12,000 in reduced fuel costs from the withdrawn unit. Hartman and Tabors miss this effect because they only explore the opportunity for increasing the price charged for the marginal unit's power, without considering the effect on prices paid to infra-marginal generation.

Hartman and Tabors show a similar sensitivity to capacity manipulation at low load levels (~5,000–8,000 MW, depending on hydro, nuclear and NUG baseload availability), where removing even 100 MW raises the market-clearing price from \$5/MWh to \$15/MWh.[1]

In the intermediate portion of the load curve, the Hartman and Tabors data shows much smaller sensitivities—removing 100–200 MW increases price only by about \$1/MWh—but the price increases for small changes in the load-supply relationship can be much larger if two or three units in the same price range happen to be unavailable. Even a \$1/MWh increase can allow for monopoly power: a utility with 3,000 MW of operating generation that withdraws 100 MW of \$19/MWh generation and pushes the market-clearing price from \$20 to \$21/MWh would be better off by

$$
\begin{aligned}
&\$21/\text{MWh} \times 2900\ \text{MWh} = \$60{,}900, \text{ minus}\\
&\$20/\text{MWh} \times 3000\ \text{MWh} = \$60{,}000, \text{ plus}\\
&\$19/\text{MWh} \times 100\ \text{MWh} \quad = \$\ 1{,}900 \text{ in fuel savings,}
\end{aligned}
$$

or \$2,800. In these examples, NU, NEES, and BECo each currently control enough capacity to profit from manipulating the intermediate and high-load market independently, while any owner of a couple hundred MWs of baseload generation would find manipulation of the baseload market to be profitable.

4.4. Conclusions regarding analyses of market power in New England

There is little in the three studies discussed above to give comfort to those concerned about market power in New England electricity markets. None of these directly address the strategic opportunities for abuse of market power in New England. In analyzing the market power issue, which is critically important to the success of electricity restructuring, it is necessary to directly consider the opportunities for large firms to profitably raise prices, in order to determine whether and to what extent this is likely to be a problem.

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[1] Hartman and Tabors report a higher load range for this transition, but they treat all hydro and pumped-hydro capacity as baseload, when much hydro and all pumped-hydro capacity is peaking.

5. SIMULATION OF NEPOOL USING ELMO

5.1. Overview

The ELMO model, developed by Synapse, has been used in analysis of market power in New York and New England. The model and its capabilities are described in Appendix A.

The basic market structure assumed is a "poolco," in which suppliers bid their resources into a central spot market, and all suppliers are paid at the market-clearing price. Cases in which particular resources are put under contract can also be analyzed. Here, for example, we consider a case in which two of the Millstone units are contracted.

In the section that follows we present a short discussion of the input data used in this analysis, followed by a description of the scenarios analyzed and the results.

5.2. Input data assumptions

The input data for this analysis are described in Appendix B. The sources include:

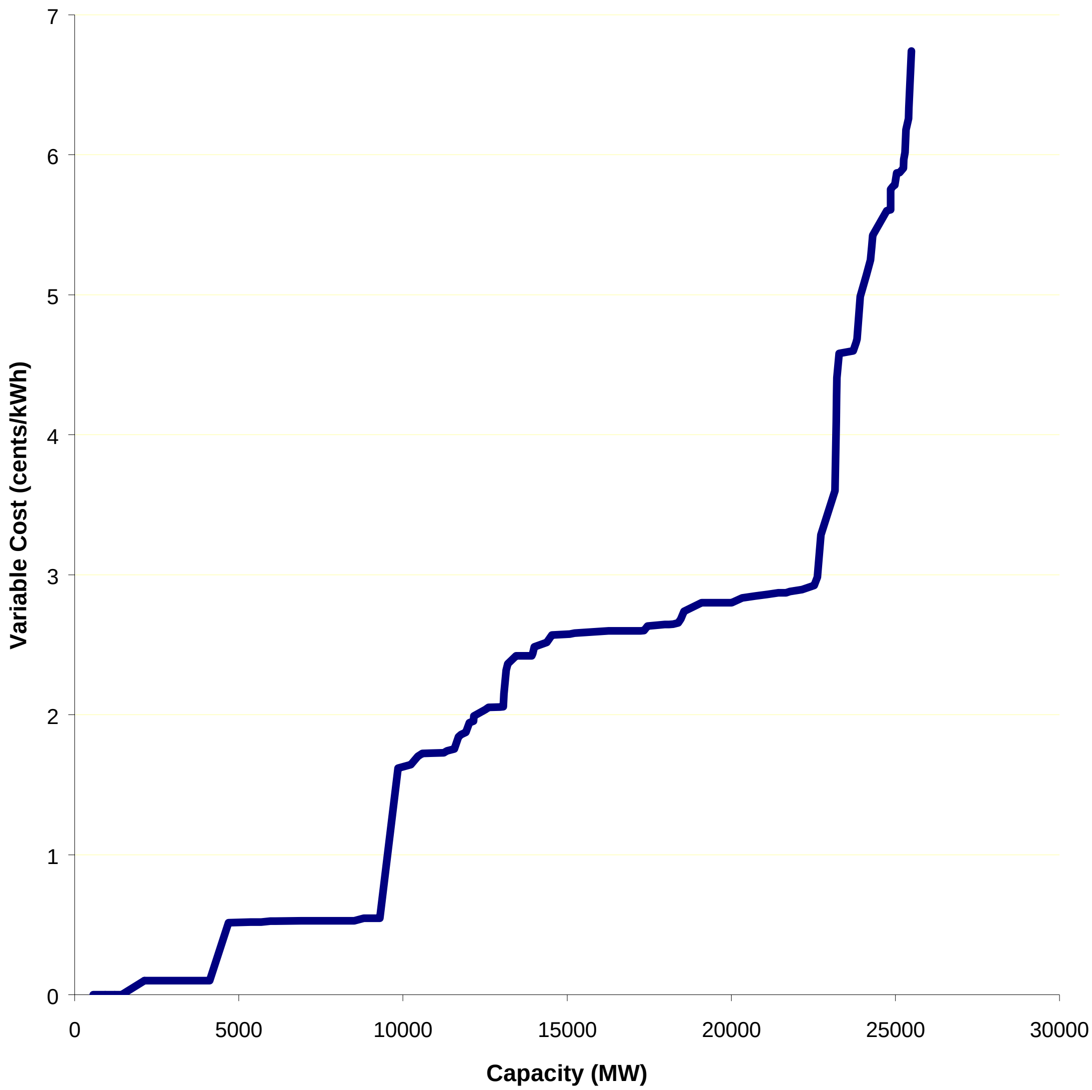
- various NEPOOL documents including the CELT and GTF reports,
- an Energy Information Administration database for capacity and heat rates,
- the Edison Electric Institute for fuel prices,
- 1995 hourly NEPOOL data for loads.

The resulting supply curve for NEPOOL is presented in Figure 1. Note that this includes several blocks of purchased power over interconnections with neighboring regions, and that non-utility generators are put in at the bottom left of the curve since they are assumed to be must run facilities. The step of about 5000 MW of capacity at roughly one half of a cent per kWh is the nuclear power plants assumed to be operating in the base case: Seabrook, Pilgrim, Maine Yankee, Vermont Yankee, and Millstone units 1, 2, and 3.[2] Note also that the capacity ratings used in this plot are derated using the outage rates listed in Appendix B.

[2] We understand that Maine Yankee may be closed permanently, as may other nuclear plants in the region. To the extent that such closures occur the market power problem will be greater than is indicated in our base case results.

Figure 1

New England Electricity Supply Curve



5.3. Scenarios and results

Many scenarios were considered. A full list along with key results is presented in Table 1. The base case results are presented in more detail in Table 2. Overall, the conclusion of these analyses is that market power is a considerable problem in New England -- much greater than suggested by the prior studies discussed in Section 4 above. Specific mitigation policies must be developed and implemented to ensure that the electricity market in New England will be an acceptably close approximation to the competitive ideal.

Table 1

Summary of Scenarios and Results

Case No.	Description	Total Cost Increase (million $)	Total Cost Increase (percent)
1	Base Case	823	29.7
11	NEPCO as market leader	179	6.4
12	BECO as market leader	58	2.1
13	CMP as market leader	3	0.1
14	Four “market leaders”	891	32.1
15	Bids fixed for 24 hours	434	15.6
16	Bids fixed for a week	207	7.5
21	Millstone 1 and 2 isolated from NU	387	13.9
22	Millstone 1 and 2 shut down	1076	36.0
23	All nuclear separated from NU	221	7.9
24	3000 MW added – none to NU	337	14.7
25	3000 MW added – 1/3 to NU	128	5.5
31	Outage rates +50 percent	1368	47.4
32	Outage rates –50 percent	494	18.5
33	Interties +50 percent	248	8.9
34	Interties –50 percent	2341	84.1
35	Fuel price +50 percent	821	23.5
36	Fuel price – 50 percent	1037	68.3

5.3.1. Base Case Results

The results for the base case are summarized in Figure 2, for specific demand levels, and in Table 2, for a full year. The lines in Figure 2 indicate that at the lower levels of demand (e.g., 8,000 MW to 10,000 MW) a bidding approach in which NU prices its output at 1.0 cents/kWh above variable cost are just as attractive to the Company as bidding at variable cost. At higher levels of demand (e.g., above 14,000 MW) NU will make more money the higher it bids.

In the base case, as in the other scenarios, a bid cap of 10 cents per kWh above variable cost was imposed. This cap is generally only limiting during peak periods.

Figure 2

Base Case: NU Net Revenues vs. Price Markup

at Different Demand Levels

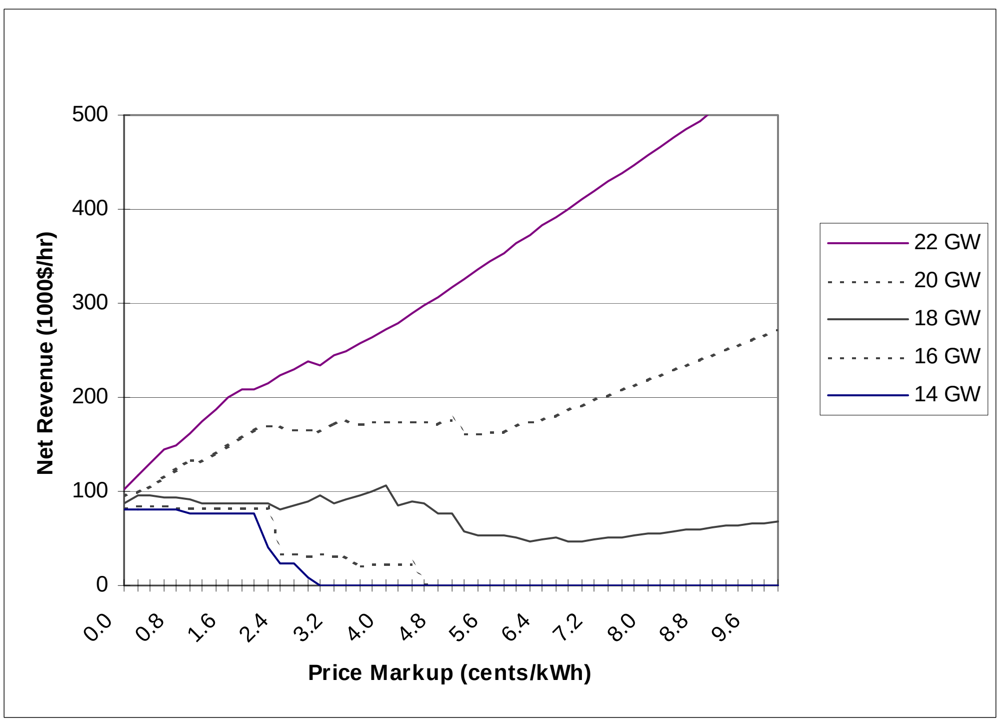


Table 2

Base Case Results for NEPOOL Simulation

	Competitive Pricing	Strategic Pricing
NU Average Generation	4705 MW	3923 MW
NU Average Cost	0.856 c/kWh	0.609 c/kWh
NU Average Selling Price	2.283 c/kWh	2.555 c/kWh
NU Increase in Net Operating Profits		13.8%
All Suppliers Avg. Generation	13,804 MW	13,804 MW
All Suppliers Avg. Cost	0.892 c/kWh	0.940 c/kWh
All Suppliers Avg. Selling Price	2.297 c/kWh	2.978 c/kWh
All Suppliers Increase in Net Operating Profits		45.1%
Increase in Cost to Consumers		$824 million/year (29.7%)

The results for the base case summarized in Table 2 indicate that over the course of a year, with demand at various levels, NU can bid significantly above variable cost in a significant number of hours, with the result being a 13.8% increase in its net operating profits, an even larger increase in the net operating profits of other suppliers, and an overall increase of $824 million per year, or 29.7%, in cost to consumers relative to a situation without market power.

5.3.2. Results for various market leaders

In the base case analysis NU, the largest electric company in New England, was specified as the market leader. That is, while all of the other firms bid their generation into the market at variable cost, the model identified opportunities for NU to price above variable cost. Cases were also analyzed in which New England Power, Boston Edison, and Central Maine Power were the specified market leader.

None of these companies has nearly the level of market power that NU does. Still, these levels might be considered significant, particularly for NEPCO, which can profitably raise prices such that consumers would pay an additional $179 million over the course of the year. This is large enough that it would make sense to have NEPCO's divestiture plan require the capacity to be split between at least two purchasers.

One case was analyzed in which the four largest companies – NU, NEPCO, BECO and CMP – jointly optimize their pricing. This is not a scenario of collusion, but rather is along the lines of the "Nash equilibrium" concept from game theory. Each large supplier is, in this case, optimizing its own strategy to maximize its individual profit, given that other large suppliers are doing the same. In this case the market power problem is somewhat greater than in the base case. We consider this case to be more realistic than the base case, because large suppliers are likely to attempt to maximize their profits.

5.3.3. Results with different treatment of NU's nuclear capacity

Two scenarios with alternative assumptions for Millstone 1 and 2 were tested:

- Case 21: in which Millstone units 1 and 2 are separated from NU, perhaps by putting them under long-term fixed contracts, and
- Case 22: in which Millstone units 1 and 2 are removed from service.

In Figure 3 and Table 3, results are presented for a case in which Millstone units 1 and 2 are separated from NU. This can be thought of as a case with these units sold to a separate entity or with these units sold under a long-term contract. Any arrangement in which the revenue to NU for output from these baseload units is not tied to the pool's market price is likely to be helpful with regard to market power. Indeed, in this simulation, we see some improvement relative to the base case. Here, the increase in the overall price to consumers as a result of strategic pricing behavior is substantial, but much lower than in the base case. The extra cost to customers is $387 million /year relative to a competitive market.

Figure 3

Millstone 1& 2 Separate:

NU Net Revenues vs. Price Markup at Different Demand Levels

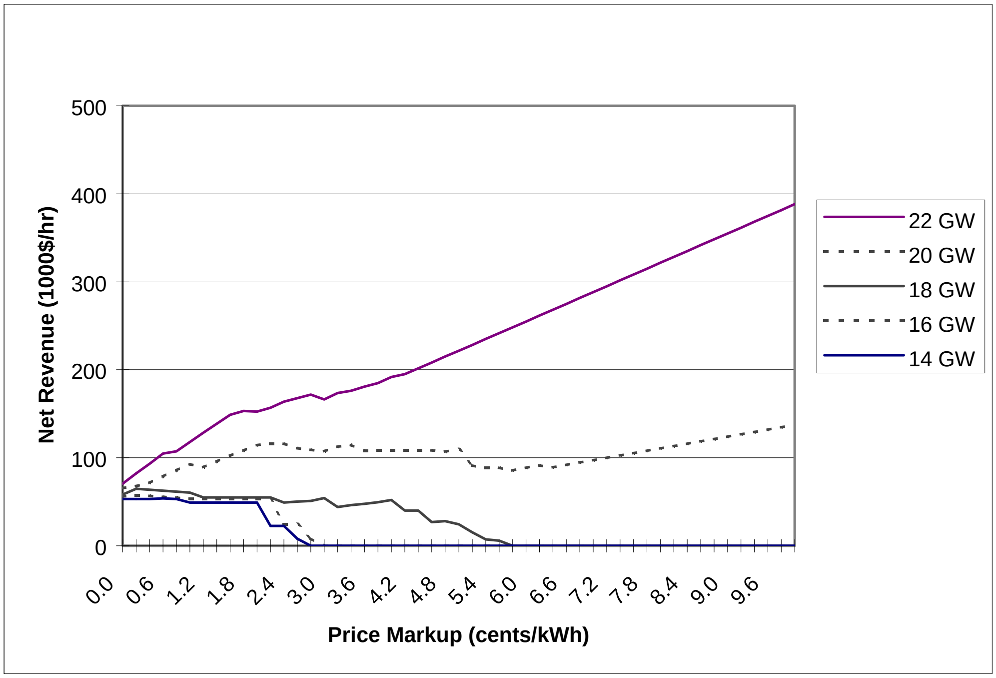


Table 3

Simulation Results: Millstone 1 and 2 Separate from NU

	Competitive Pricing	Strategic Pricing
NU Average Generation	3357 MW	2806 MW
NU Average Cost	0.990 c/kWh	0.727 c/kWh
NU Average Selling Price	2.319 c/kWh	2.472 c/kWh
NU Increase in Net Operating Profits		9.8%
All Suppliers Avg. Generation	13,804 MW	13,804 MW
All Suppliers Avg. Cost	0.892 c/kWh	0.907 c/kWh
All Suppliers Avg. Selling Price	2.297 c/kWh	2.617 c/kWh
All Suppliers Increase in Net Operating Profits		21.7%
Increase in Cost to Consumers		$387 million/year (13.9%)

The third case analyzed here is one in which Millstone units 1 and 2 are simply retired. This is not a frivolous case, as all three Millstone units are currently shut down, and the economics of restart are questionable, particularly for units 1 and 2 (see, for example, Resource Insight, 1996). In this case, even though the market concentration (as measured by the Herfindahl index or the concentration ratios) measures are improved, the market power problem is considerably worsened. This is because a tighter market, with less generating supply, works to the advantage of sellers and provides greatly expanded opportunities to exploit market power. The results for this case are summarized in Figure 4 and Table 4. The extra cost to consumers relative to a case with no market power is roughly $1 billion /year.

Figure 4

Millstone 1 & 2 Retired

NU Net Revenues vs. Price Markup at Different Demand Levels

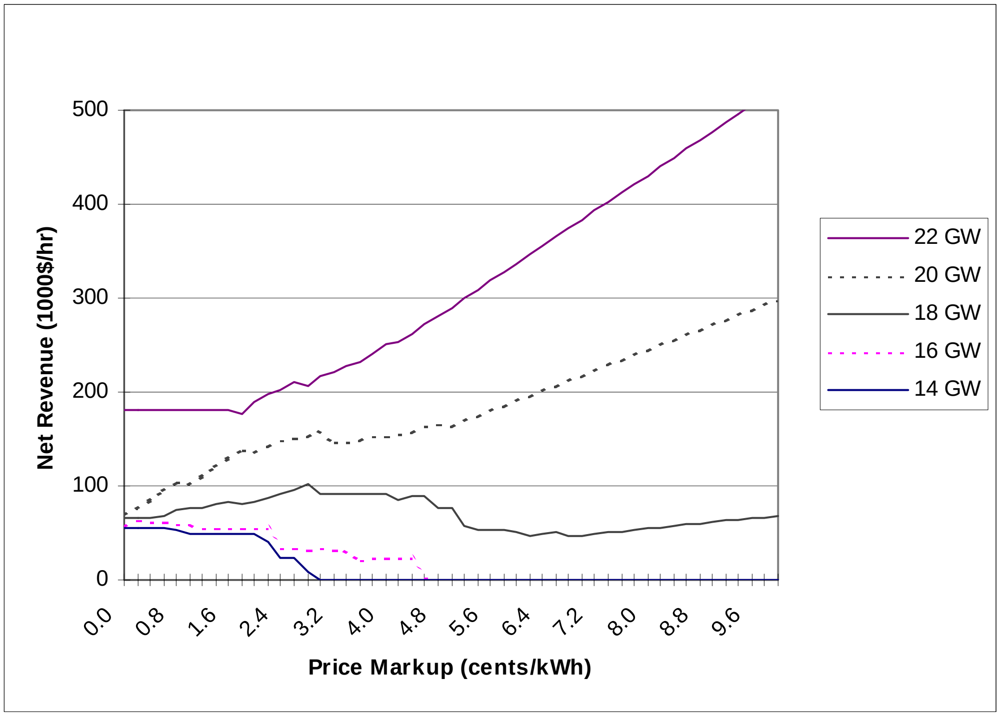


Table 4

Simulation Results: Millstone 1 and 2 Retired

	Competitive Pricing	Strategic Pricing
NU Average Generation	3783 MW	2864 MW
NU Average Cost	1.146 c/kWh	0.764 c/kWh
NU Average Selling Price	2.485 c/kWh	2.954 c/kWh
NU Increase in Net Operating Profits		23.9%
All Suppliers Avg. Generation	13,804 MW	13,804 MW
All Suppliers Avg. Cost	1.066 c/kWh	1.110 c/kWh
All Suppliers Avg. Selling Price	2.473 c/kWh	3.363 c/kWh
All Suppliers Increase in Net Operating Profits		60.1%
Increase in Cost to Consumers		$1,076 million/year (36 %)

In addition to these cases with different treatment of Millstone 1 and 2, a scenario was run with all of NU's nuclear capacity separated. This shows a considerable improvement relative to the base case, and puts the cost to consumers of market power at about three quarters of the cost for the case in which only Millstone 1 and 2 are separated.

5.3.4. Results with capacity additions

In the base case analysis, the reserve margin for New England is at about 14 percent. Two cases were analyzed in which capacity additions are made to the system. In both cases, 3000 MW of new gas combined cycle capacity was added, increasing the reserve margin to 28 percent, well in excess of what NEPOOL needs for reliability and well above what is currently projected for the region.

In the first case, one third of the added capacity is owned by NU. In the second none is owned by NU. The first case shows substantial improvement relative to the base case, with the costs to consumers from NU's market power cut to nearly half of the base case amount. This is with very little change to the HHI, since the capacity additions are roughly proportional to the ownership of existing capacity. Simply put – it helps considerably with the market power problem to have a surplus capacity situation.

In the second case, with all of the new capacity allocated to other companies, NU's ability to benefit from market power is diminished further. In this case "optimal" pricing on the part of NU will still result in an extra cost to consumers of $128 million /year, or 5.5 percent.

5.3.5. Results for sensitivity cases

Sensitivity cases were analyzed for outage rates, interties, and fuel prices. For each set of inputs, a low case and a high case were tested with the values decreased and increased by 50 percent, respectively.

The results for the outage and intertie cases show that the results are sensitive to alternate assumptions. Further analysis is warranted in both instances. For outages, modeling should ideally be done with planned outages scheduled to occur in off-peak periods and with forced outages occurring on a probabilistic basis. For interties, it would be useful to develop multi-area dispatch simulations in which the neighboring systems are modeled in conjunction with New England, so that the availability and price of power over the transmission interconnections could be determined by the model on an hourly basis.

The fuel price sensitivity cases, in which fuel prices were altered by 50 percent, represent a drastic departure from the base case prices. Additional sensitivity analyses should be done to explore the impact of changes in fuel prices relative to each other.

Finally, there would be some merit to examining combinations of these cases to see how the policies and conditions interact. For the present study, however, the range of cases listed in Table 1 was selected to represent key mitigation policies and a broad range of variation for the key input assumptions.

6. MARKET POWER MITIGATION OPTIONS

Within local "load pockets" the mitigation measures available for market power include: transmission system reinforcements, new generation, reconfiguration of loads, demand side actions, contractual methods, continued regulation, prices caps, increasing the number of owners of generation, and ISO mitigation of market power. Detailed studies may be required to determine what mix of measures is best for particular situations, and to determine what institutional arrangements best promote appropriate solutions.

At a general level, the considerations summarized above suggest that more research of horizontal market power in electricity markets is needed, and that deregulation of generation markets should move forward very cautiously prior to the availability of more information and insight into these issues. Specific policies may be needed regarding concentration or entry. Where concentration of generation is an issue, it can be addressed initially through spin off of generating assets, as in the California Commission's December 1995 decision. However, continuing vigilance will be needed, given future opportunities for reaggregation through mergers and acquisitions.

Paul Joskow has observed that "If the market power problem arises from the presence of one or two dominant firms, price caps could be applied to the dominant firms" while other smaller firms could use market-based pricing. This approach has been used by the FCC in regulating AT&T, due to AT&T's large share in the markets for some services (Joskow, 1995). Limiting price bids of generators in certain circumstances may be a useful mitigation policy to address market power.

Limits restricting ownership of generation in New England are likely to be necessary. For example, as a condition for certification to sell power into a particular pool, a generator might be required to have ownership interest in no more than a certain percent of the capacity active in that market. Policy measures to address barriers to entry might involve open access to transmission wires, power pool membership requirements, and auctioning plant sites (locations with fuel access, grid access and public acceptability are scarce). Stranded cost recovery may be the most effective policy tool for enlisting utility cooperation in setting up market structures to foster competition. It is, therefore, imperative that the problems and solutions be identified and put in place early in the transition to a more competitive electric generation market. While further analysis is surely warranted, we believe it is appropriate at this time to carefully consider requiring that suppliers in the New England bulk power market should be limited to ownership interest in some maximum percentage of the region's electric generating capacity. This would provide effective protection against market power abuse at the wholesale level.

The creation and design of the Independent System Operator for the transmission system will be a crucial element of a working regional electricity market. Also, given the special role of pumped storage hydro in the market, and the opportunities for abuse of market power by the owners of these facilities, it may be necessary to have the ISO control the pumping and generating schedule for pumped storage units.

William G. Shepherd finds that "premature deregulation, before those conditions [for effective competition] are reached, is a cardinal error and is usually irreversible" (1996). Electricity deregulators should heed this warning -- and restructure the industry at a pace and in a manner that will provide for truly competitive electricity markets.

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Appendix A

ELMO – Electric Market Optimization Model
For Analysis of Strategic Behavior and Market Power

Model Description

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1. Introduction

The Electric Market Optimization Model, "ELMO," is a computer model developed to simulate the strategic pricing behavior of participants in wholesale electricity markets. ELMO can be used to assess the extent to which market power will be a problem in specific situations, and the extent to which various policies will be effective at mitigating the market power of dominant firms.

ELMO was developed by Bruce Biewald and David White. Mr. Biewald, President of Synapse Energy Economics, Inc., has 16 years of research and consulting experience on energy economics, including electric system simulation and industry restructuring. Dr. White, Associate with Synapse, holds a Ph.D. in Engineering Systems from MIT, and has over 20 years of experience with energy systems and computer software, including 5 years at the MIT Energy Laboratory.

This document contains a basic description of ELMO and its approach to market simulation. For more information about the model and its applications please contact Synapse Energy Economics, Inc.

2. General Description

Market Power in Electricity Generation

Analysis of opportunities for strategic anti-competitive market behavior should be an essential part of assessing electric utility mergers and/or the removal of economic regulation in electricity markets. Electric industry restructuring will only produce benefits for consumers if truly competitive markets replace cost-based regulatory pricing. In a competitive market, suppliers are "price-takers," that is, their pricing and operating decisions do not significantly influence the market price. However, if a dominant supplier, or group of suppliers, can control market prices -- perhaps by withholding capacity from the market or by strategically bidding some generating units high in certain hours -- then customers may be harmed by deregulation.

ELMO can help assess the extent of market power and the effectiveness of policy options such as (1) limiting the ownership of generating capacity, (2) putting certain supply resources under long-term contract, (3) increasing transmission capability, (4) promoting demand-side price response, (5) fixing supply bids for various periods (e.g., day-ahead, week-ahead), and (6) capping bids at various levels.

Input Data Requirements

The data required for analysis of market power using ELMO include hourly customer loads, capacity and operating costs for generating units, ownership and control of generation, and transmission intertie capability. In addition, policies can be simulated:

- decreasing market concentration by breaking up ownership of capacity (or precluding a merger),

- requiring that bids be fixed a day (or more) ahead,
- requiring that bids be capped at a specific level (absolute or relative to cost),
- increasing intertie capacity, and
- providing for demand participation in the market.

Quantitative analysis of such policies can help to determine whether and to what extent they might be effective in addressing market power concerns.

Simulation Modes

The simplest simulation mode is for single-owner strategy at specified levels of demand. Operating profits for that owner are calculated for a range of bids. This can be useful in understanding whether a particular firm is likely to have opportunities to increase its profits by bidding above cost or withholding capacity from the market.

Similar simulations can be run using hourly loads, in order to assess the potential impacts of market power over the course of a year. For these cases, it is generally assumed that the market leader bids to maximize its operating profit.

More complex strategies in which market participants optimize their bids in light of the bidding strategies of others can also be simulated. Also, ELMO can be used for policy analysis, exploring the effects upon market prices of bidding rules of the Independent System Operator such as day- or week-ahead bidding.

3. Problem Formulation

Competitive Market Operation

ELMO makes several assumptions, consistent with the operations of a simple, "ideal" competitive market:

- As a base assumption for point of reference all suppliers are assumed to bid the variable costs of their resources.
- Suppliers have perfect information regarding the cost structure of the market.
- The resources are sorted in order of the bid prices and the market price is determined by the price of the last resource that is needed to meet the demand.
- All suppliers receive the market price for the resources that are used.
- The net revenue for a supplier is determined by differences between the market price and the variable costs of its resources.

From this reference, the model then explores opportunities for suppliers to increase net revenue by influencing the market price. The market price can be increased by:

a) Raising the offering price for the marginal resource. This is a no-lose situation for the owner of that resource if the new bid price is set just below that of the next resource in the production order.

b) Increasing the bid price[1] above the current market price for a resource that is currently in use. The production from the current marginal resource will increase, and the production from the resource whose price is increased will be reduced. If the surplus capacity of the marginal resource is less than that of the resource whose bid price is increased, the market price will go up. The owner's net revenues will increase if the rise in the market price (and revenues) for all of its resources offsets the reduction in production for the resource whose bid price is increased.

Technical Description

Notation and Variables

s	Supplier
r	Resource
p	Period
C_{sr}	Capacity of resource r from supplier s
V_{sr}	Variable costs for resource r from supplier s
D_p	Demand for period p
M_p	Market price for period p
B_{psr}	Bid price for resource r from supplier s in period p
U_{psr}	Actual usage of resource r from supplier s in period p
R_{ps}	Net revenue for supplier s in period p
A_{ps}	Bid adder (markup) of supplier s in period p

For a given demand period, supply must satisfy demand at minimum cost:

$$\text{Minimize} \quad \sum_{sr} B_{psr} \; U_{psr}$$

subject to

$$\sum_{sr} U_{psr} = D_p$$

$$U_{psr} \leq C_{sr}$$

The market price is determined by the highest bid price for a used resource:

$$M_p \geq B_{psr} \qquad \text{for all } U_{psr} > 0$$

The Net Revenue for supplier is then:

$$R_{ps} = \sum U_{psr} (M_p - V_{sr})$$

Thus by changing the bid prices, a supplier can influence the market price and thus its net revenues.

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[1] Increasing the bid price is the more general case of taking a resource entirely out of production.

A variety of approaches are possible for exploring variations in bid prices. The one that we use is a period specific bid adder[2] for each supplier (A_{ps}). This is added to the variable costs for each resource to give the period specific bid price.

$$B_{psr} = V_{sr} + A_{ps}$$

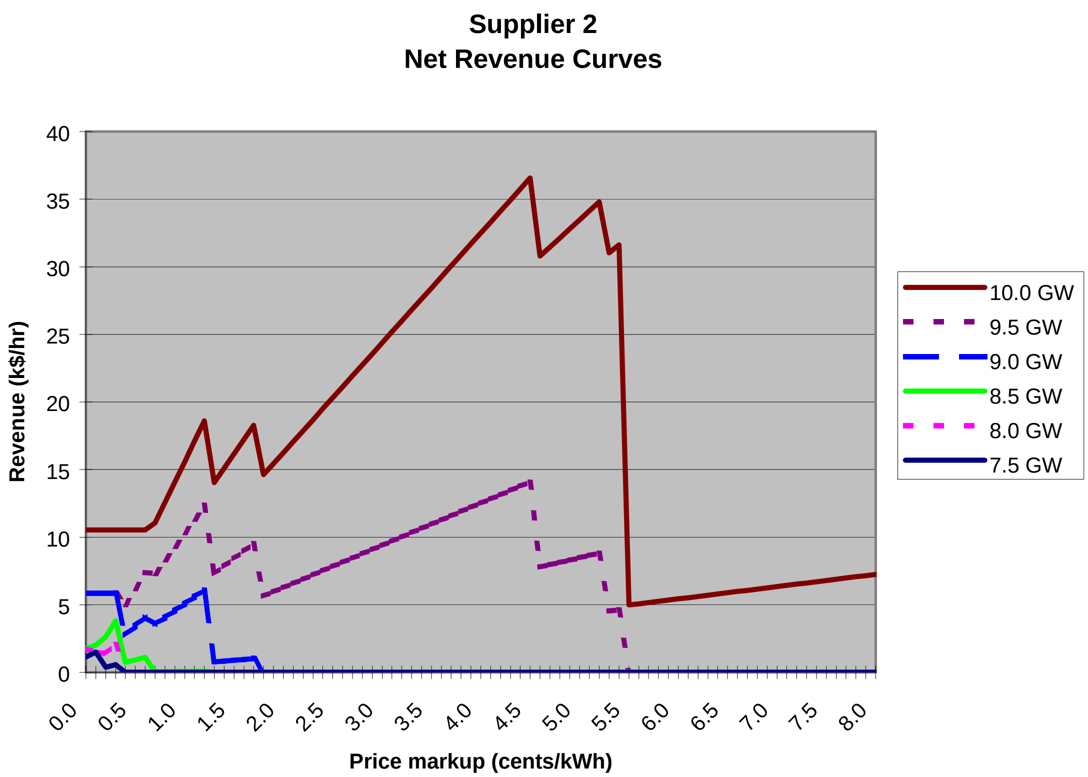
The problem then is to determine the adder that maximizes the net revenues.

$$\text{Maximize} \qquad R_{ps} = \sum U_{psr} (M_p - V_{sr}) \qquad \text{over } A_{ps}$$

This is dependent on determining the market price M_p which is the result of the previously described optimization.

[2] A supplier specific markup will find the optimal solution for a single demand period since it pushes out the higher cost resources before the lower cost ones thus maximizing the price-cost differences.

The Net Revenue is in fact non-linear with respect to the bid adder (markup) and very dependent on the other resources that are available. If one plots net revenue versus markup, the most common shape is a saw-tooth graph. That is, the net revenue increases for a while in a linear fashion to a peak, after which it immediately drops down to a lower level and starts to rise again to another peak. The upward slopes represent the increase in the bid price for the marginal resource; the descending cliffs represent when a marginal resource has been bid out of production.



The optimal bid adder for a given demand level is that of the highest peak, which may in fact in a competitive situation be zero.

Even though a supplier may raise its bid prices to increase the market price and thus its own revenues, other suppliers will benefit from the increased market price as well. It is not uncommon for a passive supplier to benefit more than the leader from increased market prices.

Comments and Observations:

1. Actual behavior can be very complex since it is based on two separate optimizations.
2. Suppliers with high usage levels have a greater potential for exercising market power.
3. Low cost resources benefit most from increased market prices.
4. The potential net revenue for a given supplier is unbounded if the resources available from the other suppliers are not adequate to meet the demand.

3. Simulation Modes

Basic Optimization Strategy for a Market Leader

The way to increase the market clearing price, and thus the net operating revenues, is to increase the bid price for the operating unit closest to the margin. This can be done in discrete sequential steps determined by the prices of the units further up the supply curve.

The algorithm is as follows:

1. Start with the operating unit closest to (or at) the margin
2. Increase the bid price to just below that of the next unused unit in the load order
3. Calculate the net revenues
4. Repeat step 2 until that unit is no longer in use
5. Go to step 1 and select the next unit and repeat until no more units are available
6. Select the bid markup which gives the highest net revenues.

The strategies are parameterized by a markup factor that is applied to all the owner's units. The above algorithm is exhaustive, but finite, and finds the best strategy for a single demand level. This type of approach is necessary since the net revenue curve is neither smooth nor continuous.

Joint Independent Optimization Strategy

If there are several potential market leaders then they may interact to affect market prices. Each operator is assumed to act independently to maximize its own current net revenues based on the existing market conditions.

The algorithm is as follows:

1. Start with a competitive market with units bid at their variable costs
2. Optimize for each leader in turn based on the market conditions as changed by the actions of the preceding suppliers. That is, if a previous leader has increased the market price by increasing the prices of its units, then the current leader optimizes their strategy based on those changed conditions.
3. Repeat step 2 until the market stabilizes or a cyclic pattern appears.

This 'take turns' approach roughly simulates supplier behavior and will find local optima, but does not search the entire solution space for a global optimum. In most situations a single market leader sets the clearing price and other 'leaders' are content to be followers. The overall effect of such joint optimization varies, but in general produces a modest increase in the market prices and total revenues.

Multiple Demand Level Optimization Strategy

While the previous basic algorithm finds the best strategy for a single demand level, the practical problem is more complicated since suppliers will typically need to set prices in advance for a period with multiple demand levels (e.g. a 24-hour day). Since the demands vary, a single set of pre-established prices may not be optimal for each subperiod.

The algorithm is as follows:

1. Determine the optimal markup for each demand subperiod in the bidding period.
2. Create a set of the subperiod optimal markup levels. If there is only one, then that markup is optimal for all the subperiods and we are done.
3. For each markup level calculate the total net revenues if that markup is applied to all of the demand subperiods.
4. Select the markup that gives the largest total net revenues for the bidding period.

This multi-demand level fixed-markup approach will not increase net revenue as much as single demand level optimization[3], but it will capture many of the high payoff periods. Its effect on market prices will be mixed, since while it might not always pick the highest potential markup for a given demand level, neither will it always pick the lowest. Prices will be pushed above competitive levels and the other suppliers may benefit more than in the single demand case.

[3] It is possible for a multiple demand level period that a strategy that uses different bid markups for different resources will produce a higher level of net revenues than a single supplier markup. However in any case it would not exceed those obtainable for a single demand level.

Appendix B

Data Assumptions for Modeling the New England Electricity Market

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Generation and Capacity Ratings

Generating capacity data was obtained from EIA Form 860 and the April 1, 1997 *NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission, 1997-2006* ("CELT Report"). The total amount of generating capacity in NEPOOL was found to be 24,420 MW. This includes Maine Yankee and the three Millstone units, but not Haddam Neck. It also includes non-utility generation. Capacity owned by more than one utility was allocated to the owners.

Fuel Costs

The following fuel costs were used in the base case:

Coal	$1.69/MMBtu
Natural Gas	$1.99/MMBtu
No. 6 Oil	$2.58/MMBtu
No. 2 Oil	$4.11/MMBtu
Jet Fuel	$4.21/MMBtu
Wood	$1.65/MMBtu
Nuclear	$0.52/MMBtu

The first three are from Edison Electric Institute's *Statistical Yearbook of the Electric Utility Industry 1995*. The others are from the *1996 Summary of the Generation Task Force Long-Range Study Assumptions* by the NEPOOL Generation Task Force and NEPLAN Staff, June, 1996 ("GTF").

Variable O&M Costs

Variable O&M costs for steam units were assumed to be $1/MWH. Variable O&M costs for peakers were assumed to be $4/MWH. Variable O&M costs for nuclear and hydro were assumed to be zero. These are round numbers, selected based upon inspection of NEPOOL's June 1995 *GTF Assumptions Book* and EPRI's Technical Assessment Guide (1993).

Pumped Storage Cost

Pumped storage facility operation was modeled as a simple generator, without representing the off-peak pumping or the opportunities for optimal scheduling. The running cost of pumped storage hydro was estimated based upon 2 cent/kWh pumping energy at an efficiency of 76 percent:

$$2.0 / 0.76 = 2.6 \text{ cents/kWh}$$

Purchases

Inputs representing purchased power for neighboring regions over interties were based upon: (1) Dr. Gilbert's testimony and exhibits submitted by Massachusetts Electric Company in Massachusetts Department of Public Utilities Docket D.P.U. 96-25, February 16, 1996; (2) New England Power Pool's FERC Form No. 715, April 1, 1994; (3) *Review of NEPOOL's Reliance on Outside Assistance*, February, 1994; (4) the CELT Report, April 1, 1997; (5) and NEPOOL's "Media Briefing Package," April 30, 1997. In the base case, we included 1,456 MW of Hydro Quebec, and 1,700 MW of other intertie.

This HQ capacity is allocated to New England companies as follows, based upon Dr. Gilbert's testimony:

BECO	137 MW
CMP	87 MW
NEP	224 MW
NU	408 MW
UI	67 MW
Others	533 MW
Total	1456 MW

The HQ capacity was priced at 2.8 cents/kWh, and the other purchased power was priced in four blocks ranging from 2.6 cents/kWh to 5.6 cents/kWh. These are based upon prices offered by HQ, inspection of marginal energy cost data for New York and New England, and consideration of plant outages on marginal costs.

Outage Rates

The following outage rates were assumed:

Nuclear	11%
Hydro	2%
Fossil	8%
Pumped Storage Hydro	5%
Tie lines	0%

These are based upon information in the NEPOOL's GTF Reports, and data from NERC's *Generation Availability Data System.*

Customer Loads

Hourly load data for 1995 was scaled to match the peak hour demand of 21,390 MW forecast by NEPOOL for 1997 (CELT Report, page 1).

Must Run Units

Hydro, nuclear and NUGs (thermal and hydro) were assumed to be "must run." It was assumed that the companies entitled to this output could not manipulate the availability or the bid price as part of a strategy to maximize profits, but that the companies would obtain higher revenues from these units as a result of elevated market clearing prices.