Exhibit No. S-1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION
OFFICE OF MARKETS, TARIFFS, AND RATES
DIVISION OF LITIGATION

BOSTON EDISON COMPANY) DOCKET NO. ER01- 890- 000

PREPARED DIRECT TESTIMONY
OF
PATRICK R. CROWLEY

WITNESS FOR THE STAFF
OF THE
FEDERAL ENERGY REGULATORY COMMISSION

WASHINGTON, DC
SEPTEMBER 5, 2001

Boston Edison Company Exhibit No. S-2
ER01-890-000

Summary of
the Prepared Direct Testimony of
Patrick R. Crowley

Mr. Crowley addresses the issue set for hearing in the Commission's order regarding whether the proposed Section 5.4 of the unexecuted Interconnection Agreement between Boston Edison Company (BECO) and Sithe Mystic Development, LLC (Sithe) is just and reasonable. To do so, Mr. Crowley analyzes the competitiveness of the New England energy market and the implications of that analysis on the allocation of interconnection costs for new generation in the Northeast Massachusetts (NEMA/Boston) area.

Mr. Crowley provides a framework for an economic analysis of the relevant markets and the consequent flows of costs and benefits associated with activities in those markets.

Mr. Crowley addresses the electric energy market in New England; congestion and uplift costs relating to the Boston energy market; the general nature of congestion causes and the effect on dispatching and price signals; the structure of the NEPOOL market, bidding strategies, and the effect on the flows of benefits from improvements in efficiencies; the evaluation of market power potential; mitigation procedures in the presence of potential market power and the effect on bidding strategies; and finally recommends the allocation of the redispatch costs arising out of this generator interconnection be socialized among all NEPOOL costumers.

Direct Testimony of
Patrick R. Crowley
Witness for the Staff of the
Federal Energy Regulatory Commission

Q. Please state your name and business address.

A. My name is Patrick R. Crowley. My business address is 888 First Street, N.E., Washington, D.C. 20426.

Q. By whom are you employed and in what capacity?

A. I am employed by the Federal Energy Regulatory Commission (FERC or Commission) as an Economist in the Division of Litigation, Office of Markets, Tariffs, and Rates.

Q. Please state your educational background and professional qualifications.

A. I graduated from DePaul University in Chicago, Illinois, in 1976 with a Bachelor of Arts degree in Economics. In 1978, I received a Master of Arts degree in Economics from DePaul University. I began work at the Commission in 1979 as an Industry Economist in the Pipeline Rates Division of the Office of Pipeline Rates. As an expert witness with the Staff litigation team from 1979 to 1992, I prepared pipeline depreciation studies, long-term forecasts of natural gas reserves and production, mortality studies of plant investment and retirements, cost behavior studies for pipeline facilities, and Mcf/mile studies. From 1992 through 1994, I worked on two teams shepherding the restructuring of two major gas pipeline companies. From 1994 through 1998, I worked on the advisory side of the Commission where I prepared reports for Commission orders regarding proposals for revised tariff terms; new services, rate designs, and tariff rates; and a

wide variety of utility reports and cost studies. In 1998, I returned to the litigation side of the Commission where I now work on electric utility, natural gas pipeline, and oil pipeline rate cases and complaint cases.

Q. Have you previously filed testimony before the Commission?

A. Yes, I filed testimony in the following rate cases:

Black Marlin Pipeline Company, Docket No. RP81-67-000;

Tarpon Transmission Company, Docket No. RP84-82-000;

National Fuel Gas Supply Corporation, Docket No. RP86-136-000;

Pacific Gas Transmission Company, Docket No. RP87-62-000;

Sea Robin Pipeline Company, Docket No. RP88-181-000;

Natural Gas Pipeline Company of America, Docket No. RP88-209-000;

Paiute Pipeline Company, Docket No. RP88-227-000;

Southwest Gas Storage Company, Docket No. RP89-60-000;

Montana Power Company, Docket No. ER98-2382-000.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to assess whether or not the proposed Section 5.4 of the unexecuted Interconnection Agreement between Boston Edison Company (BECO) and Sithe Mystic Development, LLC (Sithe) is just and reasonable. Section 5.4 proposes that Sithe bear the responsibility for redispatch costs that arise during the construction phase of the new generation interconnection.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, in addition to my direct testimony, I am sponsoring Exhibit No. S-2, which is a set of diagrams reflecting the economic analysis discussed below.

Background

Q. Please describe the electric energy market in New England.

A. The electric energy market in the New England area (NEPOOL) is coordinated and operated by the Independent System Operator (ISO-NE), which schedules and dispatches the electricity producing generators in the whole region. The ISO-NE arranges the dispatching of generators on the basis of their bids into the market. The market is also characterized by, among other things, a load pocket around Northeastern Massachusetts (NEMA/Boston) that is constrained due to a lack of sufficient transmission capacity at times of high load demand. This lack of capacity creates a congestion problem when lower-bidding generation outside of the NEMA/Boston pocket can not get into this market to serve the load. When this happens, the ISO-NE must dispatch generators out of the order that they would otherwise have been called. Because these generators' bids are higher than what the market clearing price would have been absent the transmission constraint, the costs to NEPOOL are marginally higher. This cost is known as "uplift." There are two ways to relieve this congestion and reduce the uplift costs: build more transmission lines into the load pocket or build more generation within the constrained load pocket. Here, Sithe has opted to build two state-of-the-art 800 MW generation units at its Mystic Station location within the NEMA/Boston load pocket. It has been referred to by different names in various motions, pleadings, and exhibits within this docket; I will refer to it as the Mystic Expansion Project.

Q. What are current trends in uplift costs?

A. Boston Edison submitted Exhibit No. BE-10 illustrating a dramatic rise in transmission congestion uplift cost following the restructuring of the NEPOOL market and the purchase of BECO’s generating units by Sithe. This chart is comparable to the chart shown in the ISO’s Annual Market Report for 1999-2000,

reproduced in Exhibit No S-2, page 1. NEPOOL-wide transmission uplift costs rose in 1999-2000 to a high of $25 million per month. The ISO's presentation indicates the amount of the uplift costs that were mitigated through the Market Rule 17 procedures. A similar chart is provided in the following year's Annual Market Report 2000-2001. This second chart, Exhibit No. S-2, page 2, shows that the dramatic rise in uplift costs has been halted and has fallen dramatically. For the second year 2000-2001, unmitigated transmission uplift has fallen to a level of approximately $13 million per month. Over the last several months, these costs have been mitigated down to approximately $8 million per month. Boston Edison has estimated the potential construction related uplift costs related to Sithe's new generation at between $12 million and $30 million for the duration of the construction.

Q. How much of the transmission congestion uplift is attributable to the NEMA/Boston market?

A. The ISO Annual Market Report 2000-2001 estimates that approximately 57% of the unmitigated transmission congestion uplift cost is attributable to the NEMA/Boston market.

Q. How do BECO and Sithe differ in their views of the NEMA/Boston energy market?

A. BECO sees the energy market in NEMA/Boston as being dominated by Sithe and believes that Sithe can manipulate the bidding into the market in such a way that the uplift costs during the construction period will garner Sithe market power premiums above what an otherwise competitive market would generate. In his Prepared Direct Testimony, Exhibit No. BE-1, pages 5 and 6, Mr. Clarke asserts that the NEMA/Boston market is not workably competitive enough to ensure *any* net benefits to consumers as a result of the addition of the new low-cost generation

in the load pocket. BECO believes that if Sithe is held responsible for all the uplift costs, the market can be assured that uplift will be held to a minimum, and the market will not have to pay Sithe a premium for inflated bidding during construction.

Sithe's view, as explained by Dr. Hieronymus in his Prepared Answering Testimony, Exhibit No. SMD-1, page 3, is that the addition of its new generating units will so enhance the New England energy market that congestion problems in NEMA/Boston will virtually disappear and all of NEPOOL will benefit from the new low-cost units. Dr. Hieronymus also argues on page 6 that the energy market in NEMA/Boston is a regulated market in which its older, high-cost generating units will be mitigated by the ISO such that they will operate at prices tending toward the marginal costs of the units so that no market power premiums will show up during the construction period. Hence, Sithe advocates that the costs of the uplift during construction of these units should be "socialized" among all NEPOOL consumers, just as other network system-wide improvements are currently treated.

Q. Why are redispatch costs an issue in this case?

A. Redispatch costs are an issue in this case because of their potential magnitude and the market share of the interconnecting generator. Prior to the interconnection of a generating unit, BECO conducts a system impact study to plan for any ramifications during the construction phase or adverse impacts on system operability after the interconnection. The size of the units proposed for the Mystic Expansion Project indicated significant transmission upgrades would be needed to accommodate the addition of 1600 MW. The construction work on the transmission system will require redispatching of some generating units out of merit order. The potential uplift costs caused by the large amount of redispatching

estimated by BECO gave rise to a concern that Sithe's market share in the NEMA/Boston market provided it with the ability to extract market power premiums on the uplift costs.

Q. Is it possible to isolate and measure redispatch causation?

A. It is not clear whether redispatch costs can be isolated at this time. It is possible to conduct "but for" tests analyzing the impact of a given set of conditions on the network and then altering those conditions. But if more than one condition changes at the same time, which I understand is a common occurrence, isolating the impact of any one change is difficult. Assuming we could isolate and measure the redispatch costs, or that we will soon be able to, we still must address the question of how to allocate the costs of that redispatch.

Q. How should this issue be resolved?

A. In general, those that receive the benefits of any project should pay the costs. The problem in this case is that not all the costs are clearly defined or identifiable, nor are all the benefits clearly defined or identifiable. Given the current market structure, some of the costs and some of the benefits will be socialized and some directly allocated. How we allocate those costs and benefits depends upon whether or not the market in question is a competitive market. If it is competitive, the benefits of installing more efficient production units should accrue, in large measure, to the consumers as generators bid down the market clearing prices. If it is not competitive, the benefits of installing more efficient production units will accrue, in large measure, to the generators who, rather than pass on the savings in lower prices, will keep those savings to themselves by avoiding price competition with other generators.

This is also the general principle behind the Commission's policies in cost allocation issues, as reflected in the Commission's June 28, 2001 rehearing order in ISO New England, Inc.:

> Our general principle is to assign the costs of various upgrades to those who benefit to the extent that they can be identified, regardless of how the upgrade is classified. Parties who bear the costs of such upgrades should also receive any associated incremental congestion rights. Of course we recognize that upgrades of transmission networks often benefit essentially the entire grid rendering any specific cost assignment impractical because the net benefits are too diffuse. [91 FERC ¶ 61,311 at 62,076]

The difficulty in this case is that the parties disagree about how the benefits of the new generation facility will flow. It is my contention that the market structure and the consequent competitiveness of the market will, by and large, determine where those benefits will flow. Although the issue of the competitiveness of the energy markets in New England is the subject of another case before the Commission relating to Sithe's market-based rate authority (ER01-79-000), it is central to the resolution of the issue set for hearing in this case as well.

Congestion, Uplift, & Price Signals

Q. What is merit order dispatching?

A. Merit order dispatching is the economic prioritizing and scheduling of bids into the market. As illustrated in Exhibit No. S-2, page 3, the lowest bidders are scheduled first, the highest bidders are scheduled last, if at all. The prices received by all the generators actually dispatched are based on the bid offered by the generator whose MW offer into the market makes total supply sufficient to meet the load required for that hour when added to the stack of generators scheduled previously for that hour. All generators whose bids are below that energy clearing price (ECP) (also

referred to as market clearing price) are then paid the bidding price of that last marginal generator scheduled. All bidders above that ECP are not scheduled to provide service and receive nothing, except when congestion problems force the ISO to dispatch out of merit order. In that case, the out-of-merit-order generator is paid its bid price, which may be mitigated after scrutiny by the ISO.

Q. What are uplift costs?

A. Conceptually, uplift costs are simply the difference between 1) the cost created by the market clearing price times the merit-order dispatched generation and 2) the cost created by the out-of-merit-order generation times the incremental cost of that generation bid above the market clearing price, as pictured in Exhibit No. S-2, page 3.

Q. What are the primary causes of congestion?

A. Electric markets experience uplift costs because there is insufficient transmission capacity to serve the load demanded at a given time, giving rise to congestion as supply bumps up against the constraint. The insufficiency of transmission capacity can be caused by 1) the simple fact that demand exceeds the load carrying capacity of the network lines, 2) an unexpected event causes a line to go out of service, 3) a load pocket exists in which the ability of local or imported generation to meet local requirements is constrained, 4) a generator or transmission provider restricts capacity, or 5) construction on the transmission grid requires lines to be taken out of service.

Q. How would these different types of congestion affect a constrained load pocket?

A. The different types of congestion can result in different arrangements among dispatched generators and may affect the uplift cost to the network. I have depicted the possible impacts of congestion types in Exhibit No. S-2, pages 4 through 6. The first diagram on page 4 illustrates the normal dispatching order

when no constraints are present. Generators are dispatched in the order of their bidding and the last generator dispatched sets the market clearing price. Page 5 illustrates two congestion problems. On the left is the normal congestion constraint that results in Generator E, which, although it has lowered its bid, is locked out of serving the load pocket demand due to the import constraint. The higher-bidding Generator D, within the pocket, is then dispatched out of merit order.

The right of page 5 illustrates construction related congestion in which the previously dispatched Generator C, inside the pocket, is constrained off, yet the import constraint still blocks Generator E, allowing the high-bidding Generator F within the pocket to be dispatched. Both of these examples create uplift costs from Generators D and F being dispatched out of merit order, which are passed on to the whole of the NEPOOL market.

Q. How does the potential for market power affect a load pocket?

A. A load pocket creates a market structure wherein the generators within the pocket may, at times, have a captive market with no alternatives. This condition may give the generators inside the pocket the ability to raise prices in the load pocket above what they would have been in a competitive market. Two cases are illustrated in Exhibit S-2, page 6.

The left side of page 6 illustrates Generator C, inside the pocket, taking advantage of a tight market and raising its prices. If no capacity is withheld to create a supply shortage, there is no market power problem here because the prices are rising due to scarcity.

The right side of page 6 illustrates the problem of withheld capacity in a constrained market. Here, affiliated entities agree to close one plant, at least temporarily, knowing, because of the constraint, that the remaining generation is

insufficient for the load pocket demand, and then raising the bid of the remaining plant to earn market power premiums.

Q. Why is it important to be aware of these different types of costs and types of congestion?

A. The cost to society for congestion is the inefficiency inherent in dispatching higher-cost generation ahead of lower-cost generation. Prices serve as the competitive market's tool to allocate supplies to those that value them the most. These costs are also a pricing signal to those who may be looking to enter the generation or transmission market. Yet, the existence of higher-cost generation may not in itself be a sign that entry into the market will be profitable. For example, construction related congestion may result in uplift costs, but because it is a temporary phenomenon, its pricing signal would not lead to entry.

On the other hand, higher prices or rising prices could be a signal that producers are earning handsome rewards due to the excess of demand over available supply - a clear signal that the market is ripe for entry. If, however, these windfall profits were the result of capacity restriction or parallel pricing by one or more of the producers, then the pricing signal should indicate that the market structure is the problem, not the lack of capacity on the system. Hence, knowledge of the causes of uplift problems should lead to appropriate market solutions; let the temporary problem pass, build more plant, or bring about regulatory adjustments to the market. Page 7 illustrates the benefits of adding generation within a load pocket.

The NEPOOL Market

Q. How does the NEPOOL market work?

A. The NEPOOL market has a bid-based pricing structure. Bidding is not required to be cost based, yet the more competitive the market, the more cost-based the bidding will be. In the NEPOOL market, the ISO-NE schedules or dispatches generators to meet load requirements based on their ranking order in the bidding for service - called the order of merit. See Exhibit No. S-2, page 3. In the absence of a constraint, a market such as the NEPOOL market operates as a large single market where all generators can compete to serve the load, and a single market clearing price emerges at the marginal cost of the producer that provides that last unit sold into the market. However, if the number of competitors is insufficient to maintain a competitive bidding market, there arises an opportunity for participants to exercise market power. By withholding capacity, physically or economically through its bidding strategy, a firm becomes a price setter rather than a price taker.

Q. What happens when there is some constraint?

A. The appearance of the constraint divides the market, creating a separate market on one side of the constraint. The participants in that market now see a market where demand exceeds supply, and in which prices can be raised. Just as in the larger market, the number of suppliers is an important factor in assessing whether the market structure is conducive to competitive pricing practices. If there are not enough competitors, the firm is more likely to be a price setter rather than a price taker.

Q. Why is this distinction important?

A. The distinction between price-taking and price-setting in a regulated pool-dispatched system is important because the flow of benefits caused by improvements in efficiencies in the market can be significantly different. Those

who benefit should pick up the costs of the improvements. If the difference between marginal cost and the market price can be retained by the producer, then all the benefits - *and the costs* - of the improvements should flow to the producer. If the difference between marginal cost and the market price cannot be retained by the producer, then all the benefits - *and the costs* - of the improvements should flow to the consumers. The structure of the NEPOOL market will allow us to determine how the costs and benefits of system improvements are spread among the market participants.

Evaluating Market Power

Q. Why is it important to know whether the markets are competitive?

A. As noted earlier, it is the Commission's policy to allocate costs to the parties that benefit from the project that gave rise to those costs. The flow of benefits is highly dependent on the economic structure of the market and the competitiveness of prices within the market. It is particularly important to note the difference between high demand and market power. When demand exceeds supply the competitors can and should increase prices to allocate the scarce supply among those that value it the most. Rising prices should draw in more competitors and/or more supply. But if the supply is constrained, the holders of that supply are free to test the limits of demand, as illustrated on the left side of page 6 in Exhibit No. S-2. Here, the firm reaps the differential between marginal costs and market prices. There is no market power problem in this case because the firm is providing all the capacity they have.

Market power is exercised through constraining or withholding supply or capacity from the market, as illustrated on the right side of page 6 in Exhibit No. S-2. Here, again, the firm reaps the differential between marginal costs and market

prices but it is because they have artificially created constraints. Constraints can be created physically by withholding some of the capacity or economically by bidding some of the capacity at strategically high prices at critical moments so that the rest of the capacity reaps market power premiums on its production. Again, upgrades to the network would tend to dilute a generator's ability to hold prices above marginal costs, thereby bringing benefits to the market. Hence, the costs of network upgrades should be borne by the market.

Q. How is market power detected?

A. The initial screening for market power potential is done using the Herfindahl-Hirschman Index (HHI). The HHI strives to measure the potential for sellers to posses market power by assessing the concentration of the market. The index is created by simply estimating the market share of each participant in the relevant market and then squaring the market share for each participant. A market with a single producer has an HHI of 10,000, whereas a market with ten equal sized firms has an HHI of 1000. The fewer the competitors, the higher the HHI and the less equal the market shares of the firms, the higher the HHI. The Department of Justice (DOJ) benchmark for high concentration in a market is an HHI of 1800. If the sum of the squares of all the market shares is over 1800, the market is considered to be highly concentrated, and market power becomes a concern.

Q. What does the HHI index for NEPOOL indicate?

A. The ISO-NE's analysis of the NEPOOL market, available in its Annual Market Report, indicates there are a sufficient number of competitors and a sufficient spreading of market shares within the NEPOOL market to make the market workably competitive. I have included the ISO’s NEPOOL HHI summary graphs in Exhibit No. S-2, pages 8 and 9. The graphs illustrate that the concentration in the New England market has declined significantly since the restructuring of the

market in May of 2000. At the onset of the restructured market, the HHI stood at 1900, above the DOJ benchmark of 1800. Since then, it has fallen to around 680. The second graph illustrates the market shares of the competitors over the same period. Participant "A" has lost market share while Participants "L" and "M" have entered the market. These graphs indicate that the NEPOOL market is a competitive market.

Q. Given the competitive structure of the NEPOOL market, who pays for improvements and who benefits?

A. Although the NEPOOL market is regulated in regard to scheduling and dispatching, there are a sufficient number of competitors that the pricing of energy is competitive. As noted earlier, the bid of the last dispatched generator needed to meet the load sets the price for all generators that filed lower bids. Generators bid against each other for position in the dispatching stack. It would be expected then that any improvement in efficiency by a competitor would show up in its bidding behavior as it seeks greater market share or strives to preserve its market share in the face of its rivals improvements. Over time, the market clearing price should tend to come down as well, as lower bids displace higher bids in the competition for market share. A competitive market thus allocates the benefits of an improved process by allowing the firm to garner the difference between its marginal cost and the market price, and allowing the consumer to benefit by the reduction in the overall market price. It is the generator’s hope that its improvements are far enough ahead of the curve that it can reap the differential between its marginal costs and the market price for a long enough time to recover its capital costs and earn profits. But eventually other competitors will improve their processes as well and begin bidding prices down further, lowering the market clearing price more.

In this way, the benefits of the improved efficiency will tend to flow through to the consumers, as illustrated in Exhibit No. S-2, page 10.

Q. How does the load pocket affect the assessment of market power potential?

A. The transmission constraints around Boston create a local market in which demand exceeds supply within that market. About two-thirds of the demand can be served from outside the constraint and about one-third must be served from within the constraint as illustrated in Exhibit No. S-2, page 11. The competitiveness of this smaller sub-market is also determined using the HHI.

Q. How would you define the appropriate market for analyzing market power potential in the NEMA/Boston area?

A. A critical element in the derivation of an HHI and the analysis of market power potential is the definition of the relevant market. Mere physical connection between the supplies and the demands is not sufficient; the supply must be able to get to the demand as well. A constraint, whether physical, economic, or contractual removes that piece of the supply from the market in question and narrows the supply available to the market, thereby making the market more concentrated. The market within NEMA had a load demand of 5180 MW in the summer of 2000. The import capability into the NEMA market is between 3000 and 3200 MW, which allows the competitive processes of the NEPOOL market to serve a good portion of the NEMA/Boston load. However, there is a residual demand of approximately 1980 MW that is, in essence, a captive customer base with no alternatives to the existing suppliers. It is in this market for residual demand that the potential for market power arises.

Q. What are the generating capacities within NEMA/Boston?

A. The ISO-NE web site lists the generating capacity within the NEMA/Boston area load pocket at 2876 MW. (see Exhibit No. S-2, page 12) Below is the capacity by station:

Current NEMA Capacity (ISO-NE web page)	
New Boston	760-MW
Mystic Station 4, 5, & 6	379-MW
Mystic Station 7	590-MW
PG&E Salem Harbor	743-MW
Other small units	374-MW
Total internal generation:	2876-MW
Imports	3000-MW to 3200 MW
Tot. Load	5180-MW

Or as restated by ownership:

Current NEMA Capacity		NEMA Market Shares % of NEMA Generation	HHI
Sithe	1866.96	64.91%	4213.30
PG&E	805.89	28.02%	785.12
SENE	95.93	03.34%	11.16
MNWEC	44.00	01.53%	2.34
BE	50.00	01.74%	3.03
CES	13.30	00.46%	0.21
Total Internal	2876.00	100.00%	5015.16
Imports	3000.00		
Total Load	5180.00		

Q. What do these market shares indicate about the competitiveness of the NEMA/Boston market?

A. Sithe's generation capacity in the NEMA/Boston market is in the neighborhood of 65% . Sithe and PG&E together account for approximately 94% of the residual demand in the NEMA market. The HHI for this segment of the NEPOOL market is also shown in the ISO's Annual Market Report, which I have reproduced in Exhibit No S-2, page 13. As illustrated, the HHI for the residual demand of the NEMA/Boston market is approximately 5,000 - far more than necessary to raise market power concerns.

Q. How might the presence of market power affect uplift costs within a load pocket?

A. In the absence of regulatory mitigation of bid prices, a generator or group of generators within a load pocket could bid energy into the market at levels higher than prevailing prices if they knew that a constraint would require them to be dispatched regardless of the market clearing price. This is illustrated on the left side of page 6, Exhibit No. S-2, where a generator could reap "windfall profits" by raising prices in what it knows is a market where residual demand exceeds internal supply. If no supplies are withheld, there is no market power problem.

A generator or group of generators within a load pocket could also exercise market power by withdrawing sufficient generating capacity from the market to cause supply to fall short of demand, requiring dispatching of higher priced generation out of merit order, as illustrated on the right side of page 6, Exhibit No. S-2. The same impact can be created by pricing some generation at prices so high as to effectively take it off the market, creating the shortage, while the remaining generation within the load pocket reaps market power premiums. The market power "problem" in this scenario is the creation of *artificial* scarcity through bidding strategy. The idling of the capacity creates an inefficiency to society as resources are not used, and prices are higher than necessary for supply to meet demand.

Q. Is there any evidence that would lead you to believe that generators are bidding at higher than their marginal costs?

A. Yes. The November 12, 2000 Northeast Massachusetts Congestion Mitigation Study states:

> A review of the bidding strategies that have been utilized by resources within NEMA/Boston was undertaken to determine how close these generators bid to their marginal production cost. The results of this evaluation cannot be disclosed, but highlight a significant departure from the historical NEPOOL Bidding Rules that required generators to bid at their marginal cost of production. (P.128)

The study, conducted by National Grid USA, NSTAR Services Company, and ISO-NE, assessed projected congestion costs in NEMA and the economic advisability of improved transmission upgrades in the NEMA area. In order to assess the impact of transmission upgrades on congestion related uplift costs, the model had to mimic uplift costs in order to relieve them through the upgrades. The analysis tested various bidding strategies to approximate the actual uplift costs for the period September 1, 1999 to May 31, 2000. The bidding strategy that came closest to approximating the actual uplift was a "cost plus 110%" strategy (not cost plus 10%, but cost plus 110%). The implication is that producers in the NEMA/Boston market realized that the import constraint created an opportunity to raise prices knowing that, in the short run, there were no alternative supplies, and entry by new competitors was unlikely.

Q. What does this mean for the NEMA/Boston market?

A. The high HHI figure suggests that the NEMA/Boston market is not structurally competitive because some firms have the potential to exercise market power. The NEMA congestion study's conclusions regarding bidding strategy (from September 1999 to May 2000) back up the HHI concerns and suggest that the NEMA/Boston

market was, in fact, not workably competitive. I would note here that a mitigation tool, Market Rule 17, was placed into effect on June 12, 2000 as a result of the ISO-NE stakeholders' concerns in this area.

Q. How much of the uplift cost is normal vs market power premium?

A. Assuming a competitive market, the normal uplift costs would simply be the difference between the marginal cost of the out-of-merit-order generator and the market clearing price multiplied by the amount of energy it supplied. The market power premium would be the amount of the generator's bids in excess of its marginal costs multiplied by the amount of energy it supplied. The mitigation rules, which I will discuss later, are designed to curb the potential for firms to extract market power premiums.

Q. Does a high HHI point toward a market power premium on construction related uplift?

A. Under the normal constraint conditions in a load pocket with residual demands, the generator has an incentive to add a market power premium to its bid. The construction period simply adds a tighter constraint to the situation, and presumably widens the difference between demand and available supply. However, the mitigation rules do not appear to award the generator a higher premium than it would absent the construction impact. The brackets are the same regardless of the amount of the congestion or the cause.

Q. How would you actually measure the extent of the market power premium?

A. BECO argues that this is a simple matter of calculating "but for" tests on various dispatching scenarios. Sithe argues that there can be many factors that influence line outages and redispatches in any given day, and that it is not now possible to isolate and measure these impacts. I assume that if it is not now a doable

calculation it will be in the near future. My concern here is how one would allocate the costs if they could be measured.

Mitigation

Q. How does NEPOOL mitigation work?

A. The presence of the load pockets and high HHIs illustrated by the ISO's graph on Exhibit No. S-2, page 13, prompted the NEPOOL market participants to draw up Market Rule 17 to prevent the abuse of market power when generators are dispatched out of merit order. When a generator is dispatched out of merit order, the ISO applies tests to ferret out potential market power and, if there, reset the generator's awarded price at some mitigated level.

Q. How does the test work?

A. The first test for market power is a structural screen to check whether or not there are at least three firms supplying energy in the relevant market. If there are not three, the ISO assumes the potential for market power exists and applies the next stage of tests. For generation units that regularly run in merit order, the ISO compares the current bid to the last 30 days in which that generating unit was in operation *and* in merit order. The current bid is allowed to be no higher than the average of the last thirty days' bids for the same energy market, but not lower than the current energy clearing price.

Q. What impact does this mitigation structure have on bidding strategy?

A. For a unit that tends to run in merit order, this mitigation test prevents the producer from radically altering its bidding behavior to take advantage of tight markets and would tend to keep the unit bidding in the neighborhood of the expected energy clearing prices. The fact that its history reflects being dispatched in merit order shows that it is competitive in the wider NEPOOL market. A departure from its

normal bidding strategy would bring mitigation back to the average bid and deprive it of the market power premiums in the constrained market situation, as shown on page 14 of Exhibit No. S-2.

Q. What is the test for generation that usually is not run in merit order?

A. For generation units that regularly run out of merit order, the ISO has a two-pronged test, illustrated in Exhibit No. S-2, page 15. The first test assesses the number of hours in the current run for which that generating unit must run: the fewer hours it will be needed, the higher the awarded price. The second test checks the running time out-of-merit over the last 90 days: the more frequently the unit was called on despite being out of merit, the lower the awarded price. A generator that was dispatched out of merit order over 225 hours in the last 90 days would receive a mitigated price of 105% of the energy clearing price.

Q. What impact would the mitigation structure have on the out of merit units?

A. The mitigation ratchets for units that regularly run out of merit apply to those generators that will be dispatched less than ten percent of the time. If the unit's history is one of *very* infrequent dispatching, it might bid high to ensure that it is out of merit order and try to earn the top tier award of 500% of the energy clearing price for those few times it must run. On the other hand, a unit that runs more often, yet still out of merit, as illustrated in Exhibit No. S-2, page 16, may fall in the lower range of the awards and be unable to cover its marginal costs. In fact, the mitigation plan claims that it is designed so that the generator will not be able to cover its short run marginal costs. The generator is encouraged to come to the ISO-NE to negotiate a better price that will reflect its short-run marginal costs; the ISO-NE has the right to inspect the generator’s operational cost data in determining that price. Indeed, Sithe's offer not to oppose mitigation of its bids from any units called on to relieve congestion during the construction period

indicates that the ratchets are having the intended effect. Sithe's offer suggests that the 105% and 115% ratchets (applied to the *energy clearing price*) from the mitigation rule table is not sufficient for the operation of the Boston area units and that the negotiation option of Market Rule 17 to mitigate down to 110% of their *marginal costs* is sufficient to cover the units' costs.

Q. Do the mitigation plans outlined in Market Rule 17 adequately compensate for the apparent market power potentials in the NEMA/Boston load pocket?

A. This question was brought to the Commission earlier this year in Docket No. OA97-237-003 et al., and answered by the Commission:

> Additionally, in our view, the monitoring and mitigation measures in place will suffice to deal with any issues that arise within the NEPOOL markets, regardless of whether those markets are viewed in the context of New England or smaller sub-regions within New England.
>
> [95 FERC ¶ 61,074]

It appears, therefore, that the Market Rule 17 ratchets do not provide sufficient "gaming" leverage for out-of-merit generators within NEMA/Boston to garner market power premiums above their marginal costs. Recalling that there are only two major competitors in the NEMA/Boston market, run times for out of merit units will be high enough that the low end of the mitigation ratchets would be their effective price range. In fact, data provided by Sithe regarding the operation of the New Boston generation units shows that in most 90 day periods the New Boston plants are dispatched for enough hours that they are not eligible for the higher end ratchets of the mitigation plan. Thus, Sithe is forced to weigh whether mitigation down to a competitive price level that they could not meet in the bidding markets is preferable to a negotiated rate based on its marginal costs.

Q. What does the mitigation plan indicate regarding the construction related congestion uplift at issue in this case?

A Based on my appraisal of the market structures, the mitigation plan, and the data supplied by the parties, I believe the Market Rule 17 sufficiently curbs market power potential and, consequently, the construction phase uplift costs will not carry a market power premium despite Sithe's domineering presence in the NEMA/Boston load pocket.

The Stream of Future Benefits

Q. So far you have discussed the current framework of the NEPOOL - NEMA/Boston markets. Turning to the future, what impact will the new generating units have on the NEMA/Boston generating capacity?

A. In addition to the import constraints around Boston, there are transmission constraints within Boston as well. The transmission system surrounding Mystic Station units cannot handle the total capability of both the existing generation and the planned new units. When the Mystic Expansion units are running, the others cannot run. Because the two 800 MW units being added to Mystic Station are state of the art generation units, their marginal costs will be significantly lower than the existing units in the NEMA /Boston market. Hence, the Mystic Expansion units will most likely displace the New Boston 1 & 2 and Mystic 4, 5, and 6 units within NEMA. The net additional generating capacity to the NEMA/Boston area will be approximately 450 MW.

Q. What impact will the new units have on the NEMA/Boston market?

A. The answer depends upon how Sithe will bid these units into the market. If the new units are bid in at prices competitive with the NEPOOL-wide market, they are most likely to be dispatched in merit order. Being in merit order and within the

load pocket, the new units will eliminate NEMA/Boston uplift costs. Exhibit No. S-2, page 7, illustrates the system benefit from locating generation within a load pocket. Here, a low bidding Generator G enters the market within the load pocket and is bid in merit order, displacing the other generators within the pocket and, because it is dispatched in merit order, it relieves the congestion and uplift costs.

If the new units are bid in at prices above competitive levels vis a` vis the NEPOOL-wide market, it is still likely they would be dispatched out of merit order to serve the residual demand within the NEMA/Boston load pocket. The out of merit dispatching will trigger the automatic market share screening procedure from the ISO. Because Sithe will still have a major market share, indeed, an even larger market share than they possess today, Market Rule 17 will dictate mitigation along the 'frequently running' procedure or the 'infrequently run' procedure.

Q. What impact will the mitigation procedures have on the new Mystic Expansion units?

A. If the new units are frequently bid into the NEPOOL market at competitive prices, the mitigation procedure will require mitigation back toward the average of the new units' last 30 days of bid history. So the more Sithe bids competitively in NEPOOL, the less likely it can take advantage of tight supplies within NEMA/Boston because its bids will be mitigated back down to Sithe's normal bidding pattern.

If the new units are bid into NEPOOL at higher than competitive levels, which is only reasonable if Sithe is attempting to take advantage of tight supplies within the NEMA/Boston market, it will be dispatched in-merit less frequently. The mitigation rules will then award Sithe a price based on the ratchets of Table 2 of Market Rule 17, which would be a percentage above the clearing price. But Table 2 requires that the units be run infrequently - less than ten percent of the

time. It is unlikely that Sithe would invest one billion dollars to let the new plant sit idle over ninety percent of the time in the hopes of gaming a shrinking residual demand market. Hence, the mitigation rules are not likely to play a big role in the bidding strategy for the new Mystic Expansion plants.

Q. What impact will the new units have on the NEPOOL market?

A. As indicated earlier in the discussion about the HHI market concentration indicators, NEPOOL is a workably competitive market. With the 'gaming' of the NEMA/Boston market out of the picture, Sithe must bid competitively in the NEPOOL market. Being bid in merit order, they are likely to displace other units in NEPOOL with higher bids and thus tend to bring down, marginally, the energy clearing price for the NEPOOL market.

Q. Who benefits from the impacts of the new plants?

A. Clearly, Sithe hopes to benefit from its billion dollar investment. As discussed earlier in regard to competitive markets, Sithe will garner the difference between its marginal costs for the Mystic Expansion units and the market clearing prices. But because the market is workably competitive, the Mystic Expansion units will tend to marginally lower market prices, allowing some benefits to flow to all NEPOOL consumers. Additionally, the bidding of Mystic Expansion into the market at competitive prices will rid the NEPOOL consumers of the expense associated with the NEMA/Boston congestion uplift costs. High prices in a load pocket act like a vacuum trying to suck in lower-priced supply. Constraints block the imports, creating congestion, which requires higher-priced generation within the pocket, creating uplift cost. Building generation within the pocket creates low-cost supply within the pocket, thus relieving the vacuum, the congestion, and the associated uplift cost.

Q. What other changes are coming that could affect market structure?

A. There are four major changes coming to the NEMA/Boston market in the near future which will have significant impacts on the congestion problems in NEMA and the uplift costs. The first is the addition of the two 800 MW units at Mystic Station, which is central to this case. In addition, the import interface between NEMA/Boston and NEPOOL is being upgraded to increase the import capabilities above the current 3200 MW to about 4000 MW by 2004. The increased import capability should allow more in-merit generation into the pocket and eliminate more of the out-of-merit uplift. Furthermore, there are also plans for 172 MW of additional generation owned by Southern Company (now Mirant) at Kendall Station and plans for 350 MW of additional generation owned by Cabot Power Corp. at Mystic Station. The addition of these presumably lower cost units should add in-merit generation inside the NEMA/Boston pocket. The fourth change is the move to locational marginal pricing (LMP), which should make demand more responsive to prices so that uplift costs are felt and avoided by the load.

Q. What is the upshot of all these changes?

A. The upshot of all these changes is that the NEMA/Boston market will become a more competitive market despite the rising market share apparently held by Sithe around Boston. The removal of congestion due to these changes will essentially eliminate the load pocket and its residual demand problem. Without those constraints, there is no local market in which Sithe could have or exercise market power. The relevant market is NEPOOL, and the HHI indicates no potential for market power.

Q. Do you have a recommendation with regard to BECO's proposal in section 5.4 of the unexecuted Interconnection Agreement to directly assign the construction related redispatch uplift costs to Sithe?

A. Yes. I believe section 5.4 of the unexecuted Interconnection Agreement is not just and reasonable, given the circumstances of the New England energy market. Based on my analysis of the market structure in the NEPOOL and NEMA/Boston markets, the mitigation procedures outlined in Market Rule 17, and the probable impact of the new Mystic Expansion Project generating units, I believe the New England energy markets are reasonably competitive. As such, the benefits from the interconnection of the Mystic Expansion Project, primarily lower rates and reduced congestion costs, will largely accrue to the consumers in the NEPOOL market. Indeed, such benefits over the long term should dwarf the temporary redispatch costs at issue in this proceeding. Therefore, in accordance with the Commission's policy to have costs follow benefits, it is appropriate that redispatch uplift costs be socialized among all NEPOOL costumers. Underlying this result is the incentive it provides to companies to build new generation in load pockets, thereby providing customers with additional benefits in the future, such as enhanced reliability.

Q. Does this conclude your testimony?

A. Yes.