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November 4, 2004

VIA HAND DELIVERY

The Honorable Magalie R. Salas
Secretary
Federal Energy Regulatory Commission
Dockets Room, Room 1A
888 First Street, N.E.
Washington, DC 20426

Re: *Devon Power LLC, et al.*, Docket No. ER03-563-030
Intervenor Testimony

Dear Secretary Salas:

Enclosed for filing in the above-captioned proceeding are an original and fourteen copies of the Prepared Direct Testimony and Supporting Exhibits of the Attorney General of Massachusetts, *et al*. A copy of the foregoing has been served upon all parties included in the Commission's service list via U.S. Mail.

Also enclosed are an additional two copies of the documents that I would appreciate being time-stamped and returned with my messenger. Thank you for your attention to this matter.

Very truly yours,

Stephen L. Teichler

Enclosures
cc: Honorable Bobbie J. McCartney (via Hand Delivery)
FERC Trial Staff (via Hand Delivery)
Service List

WSH\120613.1

TAB 1

Exhibit No. AG Mass., *et al.* -1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PREPARED DIRECT TESTIMONY OF

JAMES G. DALY

ON BEHALF OF

THE ATTORNEY GENERAL OF MASSACHUSETTS, *ET AL*.

DOCKET NO. ER03-563-030

NOVEMBER 4, 2004

SUMMARY OF DIRECT TESTIMONY OF JAMES G. DALY

Following an intense period of construction, the New England generation market is grossly surplus in capacity with a reserve margin of 25% versus a need of about 12% to meet required reliability standards. However, some of this capacity is in the wrong locations or there is insufficient transmission to deliver it to congested areas during times of critical need. There exists, therefore, a need to incent the construction of new generation and/or transmission in congested areas while at the same time allowing for the retirement of unneeded capacity.

In its March 1, 2004 and August 31, 2004 LICAP filings, ISO-NE has dramatically overreached by proposing mechanisms that would pay all existing capacity resources a significant sum of administratively set capacity payments that are incremental to the capacity revenues being produced in the competitive market. The numbers attributable to the August 31 filing are compelling: an additional $10.4 billion to be paid by consumers over five years (enough money to finance the construction of 17,000 MW of new capacity); an increase in average consumer rates of 2.78 cents per kilowatt hour by 2010 or about a 25% increase in the energy portion of a customer's bill; and a highly uneconomic targeted level of reliability equal to 7.5 times greater than the standard that ISO-NE is required to maintain which is a loss of load expectation of one day in ten years. The August 31 filing represents a enormous transfer of wealth from consumers to the owners of capacity resources despite a complete lack of evidence for the need for such transfer or evidence that any consumer benefits from such a transfer. ISO-NE has also failed to provide any reasonable estimate of the costs attributable to its proposal, instead opting to present a $284 million incremental cost estimate based on 2005 data,

even though LICAP wouldn't be implemented until 2006. This highly misleading analysis has been the cause of significant confusion that my testimony is intended to alleviate. Another source of confusion has been ISO-NE's characterization of its proposal as a market. In reality, the ISO-NE proposal is little more than a look-up table that sets capacity prices based on a ratio of capacity supply to demand that is devoid of most of the features of a competitive market. As such, the costs of the proposal need to be evaluated by the FERC for reasonableness for the service that is being provided since the competitive market will not set the prices that result from the ISO-NE LICAP proposal.

My testimony outlines a solution to the locational resource adequacy issue set forth above, but does so in a manner that properly directs incentive revenue to new generation capacity that is constructed where needed. This proposal keeps the current competitive ICAP market in place and does not eliminate any revenue stream currently being received by existing capacity resources.

Additionally, ISO-NE has failed to provide any reasonable justification of its criteria for establishing LICAP zones. In this testimony, I propose that loss of load expectancy be used as the sole criteria for the establishment and elimination of LICAP zones. In general, separate LICAP zones are undesirable due to concerns related to market power in areas where resource ownership is highly concentrated. Therefore, unless reliability concerns clearly indicate the need for separate zones, they should not exist.

Finally, the ISO-NE proposal as modified by ISO-NE's October 12, 2004 Motion to Lodge contains significant market power vulnerabilities related to capacity resource

retirements, de-activations and de-listing for export. These issues must be addressed before any mechanism is implemented.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Devon Power LLC, *et al*.	**)**	**Docket No. ER03-563-030**
	)	

DIRECT TESTIMONY OF
JAMES G. DALY

I. Introduction and Summary

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James G. Daly. My business address is 1 NSTAR Way, Westwood, MA 02090.

Q. ON WHOSE BEHALF ARE YOU FILING THIS TESTIMONY?

A. I am testifying on behalf of a coalition of parties affected by the ISO New England Inc. ("ISO-NE") Locational Installed Capacity ("LICAP") proposal that includes the Attorney General of the Commonwealth of Massachusetts, the Attorney General of the State of Rhode Island, The Rhode Island Division of Public Utilities and Carriers, Associated Industries of Massachusetts, the New Hampshire Office of Consumer Advocate, NSTAR Electric and Gas Corporation, Strategic Energy LLC, and The Energy Consortium; collectively, the "Coalition."

Q. BY WHOM ARE YOU CURRENTLY EMPLOYED, AND WHAT IS YOUR POSITION?

A. I am the Director, Electric and Gas Energy Supply for Boston Edison Company, Cambridge Electric Light Company, Commonwealth Electric Company, each d/b/a NSTAR Electric ("NSTAR Electric") and NSTAR Gas Company. In this capacity, I am responsible for coordinating the procurement of approximately $1 billion per year in power supplies for our retail customers. I also am restructuring a multi-billion dollar portfolio of power contracts for NSTAR Electric as well as managing a 33 BCF per year natural gas portfolio for NSTAR Gas. I assumed my present position in July 2003.

Q. PLEASE DESCRIBE YOUR BACKGROUND IN THE ENERGY INDUSTRY AND YOUR PAST EXPERIENCE WITH THE NEW ENGLAND MARKET.

A. I have 24 years' experience in the energy industry with the majority of that at the executive level managing multi-billion dollar power and natural gas portfolios. I have been involved with the New England Power Pool since 1988 and have served on the former Operations and Executive Committee. I currently serve on the Participants Committee, the most senior level committee of NEPOOL. I chaired the NEPOOL Governance Committee in 1998 and 1999 with responsibility for replacing the former utility-dominated voting structure with the sectoral voting structure.

I served from 1988-2000 in various positions including Senior Vice President of Unitil Service Corporation, with lead responsibility for energy procurement, operations and management to various Unitil subsidiaries. From 1998-2000, I was President of Unitil Resources, Inc., providing consulting services to major

energy companies and international and governmental bodies, including Enron Corporation, the World Bank, the Government of India, Hydro Quebec and others. These services included assistance in power contract negotiations, litigation and, in the case of the Government of India, best practices for contracting with independent power producers. In the early 1990's, I also was responsible for marketing power for Great Bay Power Corporation and assisting it in its emerging from Chapter 11 which involved the assessment of the forward markets for investors. Great Bay is, I believe, the first merchant nuclear plant owner in the country. During 2000-2001, I held the position of Executive Vice President, Network Operations for Enermetrix.com, Inc., a start-up Internet-based network for large retail customers to procure electricity and natural gas in competitive retail markets. From 2001-2003, I was Director of Power Market Development for Sprague Energy Corporation where I was responsible for developing a start-up retail electricity business servicing large customers. From 1980 to 1988, I was with the Electricity Supply Board Ireland, southern Ireland's single major utility, in various positions in the areas of marketing, designing distribution systems and interconnecting independent power producers.
I graduated in 1980 from Trinity College in Dublin, Ireland with a Bachelor Degree in Electric Engineering and from University College in Dublin, Ireland with a Masters in Industrial Engineering.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My first objective in this testimony is to demonstrate that ISO-NE has proposed a LICAP mechanism that fails on many fronts to produce results that are just and

reasonable. I will show that the ISO-NE proposal is flawed in both its design and its application. Using ISO-NE's own numbers, I will demonstrate that the potential cost impact to consumers is staggering, especially considering the fact that the ISO-NE proposal is an experimental market design that has not been proven to meet its objectives. My second objective is to propose an alternative LICAP mechanism that has been designed to provide appropriate incentives to investment in capacity resources at an overall cost that is proportional for the incremental benefits received. This alternative LICAP proposal targets incentives directly to new entrants and I will demonstrate that this is appropriate. My third objective is to show that ISO-NE has not developed a reasonable and rational set of criteria for the development and elimination of LICAP zones. I will further show that the NEMA/Boston sub-region does not qualify under any reasonable definition of a LICAP zone. My fourth objective is to discuss the flaws in ISO-NE's treatment of market power and offer constructive suggestions on how these flaws can be addressed in the design of a LICAP market. My fifth and final objective is to discuss the mechanics of bidding and settlement and offer solutions to many of the unresolved issues related to these aspects of the LICAP market.

Q. ARE THERE ANY CRITICAL POINTS THAT YOU WOULD LIKE TO DISCUSS AT THIS TIME?

A. Yes, before discussing the details on the LICAP proposal, I would note certain overarching considerations. First, the implementation of any LICAP scheme will result in a change in rates for the buyers of capacity. It is imperative that FERC find these rates to be just and reasonable under traditional ratemaking principles.

The LICAP proposal is an administrative construct that is designed to provide suppliers with extra revenue and hence cannot be reviewed under the deferential standard accorded to market-based rate authority. A true market would have both buyers and sellers that have the freedom to buy and sell as they see fit. Under ISO-NE's proposal, buyers have no freedom whatsoever. They are simply captive buyers who must purchase capacity. The only freedom to make decisions rests in the hands of sellers under the delisting rules. In actuality, the ISO-NE proposal is a rate case which sets the rate for capacity. Secondly, the avowed purpose of LICAP is to incent a specific type of conduct, namely, the construction of new and, supposedly, low-cost capacity. Hence, the Commission must assure that the incentive is reasonable in terms of the quantity of conduct desired and that compensation is directed only to those that respond to the incentive. Any LICAP scheme that results in an equal compensation of all existing capacity that is currently paid under existing market structures in order to incent new investment for new services will undeniably result in rates that fail the just and reasonable rate standard. There is simply no way mathematically to provide adequate compensation to new entrants and retain just and reasonable rates without targeting the incentive payments to those new entrants who provide the service.

Q. IS THE COALITION SPONSORING ANY OTHER TESTIMONY IN THIS CASE?

A. In addition to this testimony, the Coalition is sponsoring the testimony of Dr. Jay Lukens, of Lukens Energy Group and Mr. Charles Salamone, Director of System Planning of NSTAR. Additionally, the Coalition is sponsoring the affidavit of Mr.

Glenn Haringa, Consulting Engineer with General Electric International, Inc., Power Systems Energy Consulting ("GE").

II. Background

Q. WHAT PRECEDED DEVELOPMENT OF THE ISO-NE'S LICAP PROPOSAL?

A. This proceeding originated on February 26, 2003 with the filing of various cost-of-service Reliability Must Run ("RMR") contracts between ISO-NE and NRG covering 1,728 MW of generating capacity, including the Devon Power station, located within Connecticut and the Southwest Connecticut ("SWCT") Designated Congestion Areas ("DCAs"). The impetus for these unit-specific agreements arose because ISO-NE determined that, although the generating units were needed for system reliability, the units would not otherwise receive adequate compensation in the New England Standard Market Design.

By order dated April 25, 2003,[1] the Commission rejected the RMR agreements, and allowed collection of only going-forward maintenance costs through a tracking mechanism administered by ISO-NE. In this order, the Commission expressed concerns about the impact of RMR agreements on the competitive market and directed that ISO-NE, rather than focusing on and using stand-alone RMR agreements, instead "incorporate the effect of those agreements into a market-type mechanism."[2] The Commission required revisions to NEPOOL Market Rule 1 to lessen the need for RMR agreements and to instead allow low-capacity generating units operating in DCAs to increase their bids to recover their

[1] *Devon Power LLC, , et al*., 103 FERC ¶61,082 (2003) ("April 25 Order").
[2] *Id*. at P29.

fixed and variable costs, and allow the energy bids of peaking units to determine the LMP through the Peaking Unit Safe Harbor ("PUSH") bidding mechanism. The April 25 Order also directed ISO-NE to file by March 1, 2004, for implementation by June 1, 2004, "a mechanism that implements location or deliverability requirements in the ICAP or resource adequacy market. . . so that capacity within DCAs may be appropriately compensated for reliability."[3] The April 25 Order, therefore, was narrow in scope: the Commission's directive to ISO-NE was limited to implementation of a locational solution to replace RMR contracts and PUSH to compensate units that provide local reliability. Because the market, as designed, does not permit these generators to recover the necessary operating costs, unit-specific RMR agreements were proposed to remedy this precise set of circumstances. In requiring the development of location or deliverability requirements, the Commission sought to reduce the need for RMR contracts, but made clear that the purpose of any such requirements is to ensure appropriate compensation for reliability for DCAs.[4] Indeed, the June 2, 2004 order in this proceeding[5] reiterates that the primary goal is to ensure that generators needed for reliability are appropriately compensated.[6]

ISO-NE submitted its LICAP proposal on March 1, 2004 ("March 1 Filing") in response to the Commission's directive. The ISO-NE LICAP proposal goes far beyond the limited scope of the Commission's April 25 Order and proposes several additional changes to the capacity market that were not required or raised

[3] *Id.* at P37.
[4] *See e.g., id.* at P37.
[5] *Devon Power LLC, et al.*, 107 FERC ¶61,240 (2004) ("June 2 Order")
[6] *See e.g.*, June 2 Order at P1.

by the Order. For example, the ISO-NE proposal includes: a fractured locational capacity market based on improperly designed price curves labeled as demand curves; transition payments that replace RMR contracts and PUSH; and Capacity Transfer Rights, none of which were prescribed by the April 25 Order.

In addition, the ISO-NE has failed to address the critical issue raised by the Commission in the April 25 Order, namely, the lack of local operating resources in New England. Rather than include a mechanism that directly addresses payments that may be necessary to maintain reliability within specific areas in the region, the ISO-NE's broad-based proposal pays all generators no matter where they are located, what service they provide or whether or not these generators provide necessary operating reserves or require such payments for continued operation. Put another way, ISO-NE proposes to extend LICAP payments to all capacity suppliers, as opposed to targeting payments to capacity needed for reliability only which is what is needed to replace the units on RMR agreements.

This proceeding started with a clearly defined scope that addressed specific concerns. It has mushroomed into a needlessly complex proceeding that has spawned a costly LICAP proposal submitted by ISO-NE which is both overinclusive and underinclusive. On August 31, 2004, ISO-NE filed direct testimony in this proceeding ("August 31 Filing") that has resulted in significant changes to its case. The original downward sloping price curve was replaced by a new "kinked" downward sloping price curve. Along with this new price curve came a new methodology for calculating the reference cost of a new peaking generator as well as several concepts that were new to the proceeding such as

adjustments for actual infra-marginal energy rents and availability during critical hours. On October 12, 2004, ISO-NE filed a Motion to Lodge new measures for the prevention and mitigation of market power abuses. ISO-NE has asserted that its proposal will not work absent the changes proposed in this motion.

Q. DID ISO-NE'S LICAP PROPOSAL WIN THE NECESSARY SUPPORT OF THE NEPOOL PARTICIPANTS COMMITTEE?

A. No. ISO-NE's proposal failed to garner the required two-thirds vote of the NEPOOL Participants Committee for approval. ISO-NE nonetheless decided to submit its LICAP proposal unilaterally on March 1, 2004. The August 31, 2004 proposal was not presented to the NEPOOL Participants Committee and to my knowledge no stakeholder input was requested by ISO-NE in its development.

III. <u>The August 31, 2004 ISO-NE LICAP Proposal</u>

Q. PLEASE DESCRIBE THE COST IMPACT OF ISO-NE'S LICAP PROPOSAL.

A. To begin with, it would be useful to examine some very important numbers. First of all, consider a situation where the entire pool has an aggregate level of installed capacity equal to 5.8% above the Objective Capability[7] (OC) level. At this level of installed capacity, the loss of load expectation ("LOLE") is approximately 1 day in 75 years.[8] This level of installed capacity is also ISO-NE's targeted equilibrium level of installed capacity, called C_{Target}.[9] Under the ISO-NE's price

[7] OC is the minimum level of capacity required to meet a loss of load expectation standard of 1 day in 10 years. Another way of expressing OC is that it is the sum of peak load plus the minimum required reserves.
[8] *See* ISO-NE March 1 Filing, Attachment G, "Development of the Demand Curve Component of the Locational ICAP Market Design", by ISO-NE Markets Development Department, Appendix B, Table 2 (hereinafter referred to as "ISO Table 2").
[9] Prepared Direct Testimony of Steven E. Stoft on behalf of ISO New England Inc., filed on August 31, 2004 ("Stoft Testimony") at 13:18-19.

curve, C_{Target} calls for 31,069 MW of capacity at an administratively-determined price of $7.00/kW-month. A simple calculation of (Installed Capacity x Curve Price [in dollars per kilowatt month] x 1,000 [price conversion to megawatts] x 12 months) is as follows: 31,069 MW x 7.00/kw-month x 1,000 x 12 = $2.61 billion. After subtracting forecasted infra-marginal rents of $0.48/kw-month,[10] as well as ISO-NE's calculations of current ICAP costs, RMR contract costs and availability offset, the additional cost to consumers to maintain the existing over-supply of capacity is approximately $1.97 billion.[11] When spread out over New England's 6.5 million[12] customers, this equates to an extra $303 per year for each customer on average, which translates to about an extra 1.5_cents per kilowatt hour ("kwh") or an increase of 25% to the energy portion of the average customer bill.

Secondly, consider a situation where the Installed Capacity ("IC") is equal to OC. In this case, there is enough capacity to meet the forecasted peak load plus the traditional reserve margin of approximately 12%. OC is currently set at 29,366 MW for New England, which results in a unit price of $17.11/kW-month on the ISO-NE's price curve. To simply provide the amount of capacity that has historically been deemed to be optimal would result in the following consumer impact: 29,366 MW x $17.11/kw-month x 1,000 x 12 months = $6.03 billion. After subtracting the infra-marginal rents and existing costs, the annual price tag

[10] *See* Workpapers related to Prepared Direct Testimony of Mark Karl on behalf of ISO New England Inc., filed on August 31, 2004 ("Karl Testimony"). Specifically, see spreadsheet 2004-08-16 New CT IM Revenue Calc in Workpapers CD under file "Karl.docs."
[11] The $1.97 billion number also takes into account different clearing prices per zone (per ISO-NE witness John Reed testimony).
[12] See http://www.iso-ne.com/about_the_iso.

is $5.45 billion,[13] or $838 per year per New England customer, which translates to about an extra 4.2 cents per kilowatt hour ("kwh") or an increase of 69% to the energy portion of the average customer bill. When asked about numbers of this magnitude in deposition, Dr. Stoft stated that "[i]f it was lots higher than it is today, that means that we've totally screwed up the market design and things have gone completely haywire; I can't imagine how that could happen. But if everything went haywire and I understood nothing and that happened, it's a bad thing." [14]

This additional cost is incurred when there is sufficient capacity in the pool to meet the Northeast Power Coordinating Council ("NPCC") criteria of 1 day in 10 years LOLE. The magnitude of these numbers is staggering. In its filing, ISO-NE has deftly avoided mention of these cost impacts. Below is a table that breaks down the customer cost impact of ISO-NE's proposed LICAP structure at varying levels of IC as a ratio of OC ("IC/OC") (Table 1).

Table 1

OC	IC	IC/OC	Reserves Level	LOLE (1 day/ N year)	Incremental Cost Impact ($M)
29,366	29,366	1.00	12%	11	$5,447
29,366	29,660	1.01	13%	15	$4,686
29,366	29,953	1.02	14%	20	$3,911
29,366	30,247	1.03	15%	27	$3,080
29,366	30,541	1.04	16%	36	$2,422
29,366	30,834	1.05	17%	48	$2,179
29,366	31,069	1.058	18%	75	$1,969
29,366	31,275	1.065	19%	100	$1,796
29,366	32,303	1.10	22%	286	$820
29,366	32,766	1.116	23.6%	459	$284
29,366	32,890	1.12	24%	526	$231

[13] The $5.45 billion number also takes into account different clearing prices per zone (per ISO-NE witness John Reed testimony).
[14] Transcript of deposition of ISO-NE witness Steven E. Stoft ("Stoft Deposition"), Vol. 2 at 34:2-7.

29,366	33,771	1.15	27%	1250	$0

From the above table it is clear that when IC equals OC, the loss of load expectation is about one day in 11 years which equates to a reserve margin of 12%. It is also clear that a level of IC that is 1.15 times OC the LOLE is one day in one thousand two hundred and fifty years and the reserve margin is 27%. At this 27% reserve margin of 1.15 times OC is the point on the curve that the ISO-NE ceases to value capacity. This is an enormous reserve margin that provides a totally unrealistic level of reliability of one day outage in 1,250 years which has not been justified by ISO-NE.

Also, for illustrative purposes here is a table of NEPOOL LOLE levels at varying levels of IC/OC. This data is taken directly from an ISO-NE published document.[15]

Table 2

IC/OC (1)	LOLE (2)	LOLE (3)	IC/OC (1)	LOLE (2)	LOLE (3)
1.15	0.0008	1 in 1,250	1.07	0.0085	1 in 118
1.14	0.0010	1 in 1,000	1.06	0.0114	1 in 88
1.13	0.0014	1 in 714	1.05	0.0207	1 in 48
1.12	0.0019	1 in 526	1.04	0.0279	1 in 36
1.11	0.0026	1 in 385	1.03	0.0376	1 in 27
1.10	0.0035	1 in 286	1.02	0.0507	1 in 20
1.09	0.0047	1 in 213	1.01	0.0683	1 in 15
1.08	0.0063	1 in 159	1.00	0.0920	1 in 11

(1) Installed Capacity/Objective Capability
(2) LOLE expressed as a probability for loss of load in a year
(3) LOLE expressed in terms of 1 day in "x" number of years loss of load expectancy

When the numbers in this table are put into perspective, it becomes quite apparent that ISO-NE is attempting to maintain a level of reliability that exceeds its

[15] ISO Table 2.

mandated 1 day in 10 year level without regards to cost. The NPCC 1 in 10 standard exists as a point of balance between reliability and cost. When pressed on the issue in deposition, ISO-NE witness LaPlante acknowledged that OC was the proper measure.[16]

Q. HAS THE COALITION PERFORMED ANY ANALYSIS OF FUTURE LICAP COSTS? IF SO, PLEASE SUMMARIZE THIS ANALYSIS.

A. The Coalition engaged GE to develop local sourcing requirements ("LSRs") for a five-year period beginning in 2006. GE developed the LSRs for each proposed LICAP region using the same GE Multi Area Reliability Simulation ("MARS") model that ISO-NE uses.[17] The Coalition then calculated Capacity Transfer Limits ("CTLs") and applied ISO-NE's price curve to each LICAP zone proposed by ISO-NE to project LICAP costs for this five-year period using ISO-NE's own price clearing model. Despite the magnitude of the potential cost impact, ISO-NE failed to perform this necessary analysis. This is a gross deficiency in the ISO-NE filing. Instead of considering the potential long-run costs attributable to its proposal, ISO-NE provided a one year cost estimate of $284 million using 2005 as an example, which is highly misleading, especially considering that its proposed LICAP scheme wouldn't be implemented until 2006. The tables below set forth the projected LICAP cost for 2006 through 2010 that ISO-NE was either unable or unwilling to calculate. The numbers are quite compelling when the costs are compared to the LOLE and the resulting inefficiency is evidenced.

Table 3

[16] Transcript of deposition of ISO-NE witness David LaPlante ("LaPlante Deposition"), Vol. 1 at 79:12-22 and 80:1-5.
[17] *See* Exhibit No. AG Mass., *et al*. -2.

Clearing Price by Zone in Dollars per kw-month

	NEMA	ROP	Maine	Rest of CT	SWCT
2006	$3.64	$3.64	$3.64	$3.64	$3.64
2007	$5.32	$5.32	$5.32	$5.32	$5.32
2008	$6.96	$6.96	$6.96	$6.96	$6.96
2009	$8.62	$8.62	$8.62	$8.62	$8.62
2010	$13.02	$13.02	$13.02	$13.02	$13.02

Table 4

Net Incremental Cost Impact by Zone ($Millions)

	NEMA	ROP	Maine	ROCT	SWCT	TOTAL
2006	$140	$407	$68	$22	$85	$722
2007	$257	$677	$112	$100	$168	$1,314
2008	$373	$941	$156	$176	$250	$1,896
2009	$489	$1,208	$201	$252	$333	$2,483
2010	$799	$1,923	$319	$457	$552	$4,050

Table 5

Net Incremental Retail Rate Impact by Zone (cents per kilowatt hour)

	NEMA	ROP	Maine	ROCT	SWCT	TOTAL
2006	0.54	0.70	0.58	0.13	0.49	0.22
2007	0.97	1.14	0.94	0.60	0.94	0.92
2008	1.38	1.56	1.28	1.04	1.37	1.32
2009	1.77	1.96	1.62	1.46	1.79	1.72
2010	2.83	3.06	2.52	2.59	2.91	2.78

As can be seen in Table 3, under a reasonable base-case scenario,[18] prices in all LICAP regions converge in 2007. The additional capacity cost in 2007 is projected to be approximately $1.3 billion. This additional cost is imposed upon consumers in New England when the estimated LOLE is no worse than 0.0063, or

[18] Assumptions in base case: OC begins at 29,366MW and increases at 2% annually; 2005 - Kendall ST1, Jet2 and CT retire (187MW); 2006 – NSTAR 345 kV upgrade phase I (900MW), New Boston I retires (350MW), SWCT Reliability Project phase I (550MW), Kleen Energy online in CT(620MW); 2008 – NSTAR 345 kV upgrade phase II (200MW), SWCT Reliability Project phase II (850MW).

1 day in 159 years. In 2008, the rest of pool alone faces an additional cost of almost $1 billion, while total additional costs approach $1.9 billion. At that point, the LOLE is approximately .01, or 1 day in 100 years. Additional costs of this magnitude would be almost certain to occur under the ISO-NE proposal as the calculations are based on a highly realistic scenario, not a hypothetical "what if" scenario. As another point of perspective, consider that the ISO-NE proposal would result in approximately $10.4 billion in payments to existing capacity resources from 2006 through 2010. At ISO-NE witness John Reed's development cost of around $600 per kilowatt,[19] this equates to the full capital cost of more than 17,000 MW of new frame units. As I discuss in detail later in this testimony, there are other situations that can easily arise under ISO-NE's proposal that could drive costs significantly higher than those listed above such as economic withholding through resource retirements and exports. The numbers are very large and they are quite real.

Q. WHAT IS THE APPROPRIATE STANDARD FOR DETERMINING WHETHER CAPACITY PRICES ARE APPROPRIATE?

A. I am not an attorney, but I will summarize the position that will be briefed by counsel at the appropriate date in this proceeding. As a general proposition, the just and reasonable standard requires the Commission to find that a rate or charge for a jurisdictional service falls within a "zone of reasonableness" that is bounded at the lower end by the requirement that the rate not be confiscatory to the service provider and at the top end that it not result in excessive rates to consumers.

[19] Prepared Direct Testimony of John J. Reed on behalf of ISO New England Inc., filed on August 31, 2004 ("Reed Testimony") at 20: 6-7.

Rates are not excessive to consumers where they are only high enough to permit providers to recover their cost of service plus a reasonable return. Higher incentive rates may be allowed but the Commission must find that the level of the incentive is no higher than that which is required to produce the desired quantity of additional energy or service. With respect to installed capacity, numerous factors must be considered. If existing capacity is to be compensated, the starting point for the analysis would be how much it costs to produce installed capacity. If the objective is to incent new capacity, then we would have to establish the cost of new capacity. And, of course, where there are different options to secure a desired outcome, the just and reasonable standard generally favors the least cost alternative. Any overall pricing proposal that imposes excessive costs on consumers fails to meet the just and reasonable standard. While ISO-NE's witness, David LaPlante, acknowledged that the LICAP proposal must pass under the just and reasonable standard,[20] in its filing ISO-NE gave little or no heed to balancing the cost of its proposal against traditional metrics for the establishment of rates consistent with that standard. When asked in deposition about whether the application of the just and reasonable standard can be made to the demand curves, Dr. Stoft stated that "In the abstract, I don't think you can answer that question. I can't answer it."[21]

Q. IS ISO-NE'S PROPOSAL CONSISTENT WITH THE DEFINITION OF A COMPETITIVE MARKET?

[20] Prepared Direct Testimony of David LaPlante on behalf of ISO New England Inc., filed on August 31, 2004 ("LaPlante Testimony") at 6:21-23.
[21] Stoft Deposition, Vol. 1 at 54:21-22.

A. No, it is not. As is detailed more thoroughly by Dr. Jay Lukens, ISO-NE has proposed an administrative payment mechanism for capacity resources. This mechanism is loosely based on cost of service principles by reference to the cost of a new peaking generation unit in New England as described in Mr. John Reed's testimony. While this mechanism does allow sellers to bid their desired price for capacity in certain circumstances, the mechanics of settlement ensure that both buyers and sellers are mere price takers (captive price takers in the case of buyers). The sloped line is really a price curve that has been entirely administratively determined by the ISO. Its only resemblance to a demand curve is that it produces lower prices at higher levels of supply, and conversely higher prices as supply decreases. In a normal market, the demand curve reflects the economic preferences of the consumers of the proffered commodity. Here, the curve is administratively derived to produce a pre-determined series of prices that are entirely divorced from the economic preferences of those who actually pay for the product. In addition, there is no real supply curve. The amount of capacity is simply plotted on the horizontal axis, with the price set at the vertical intersection at that point on the price curve. In competitive markets, supply curves normally reflect the continuum of the marginal costs of the suppliers in the market. Thus, the ISO-NE has concocted an artificial demand curve and an artificial supply curve and when it equilibrates the two will have an artificial market equilibrium, which it will then use in order to determine the price it wants to pay generators. Since these are artificial constructs, nothing prevents the ISO-NE from arranging their parameters in such a way that the ISO-NE achieves whatever level of

payment that they see fit. This is problematic from a regulatory perspective because the FERC has made clear that it views rates as being reasonable if they arise from either a cost of service proceeding or result from the workings of a competitive market. Since it is clear that there is no real market here, then what would be appropriate would be to hold cost of service proceedings on the appropriate level of payments to new investment since that is the service that the ISO-NE is seeking in incent.

Q. WILL THE ISO-NE PROPOSAL RESULT IN JUST AND REASONABLE RATES FOR CAPACITY?

A. The ISO-NE proposal fails any reasonableness standard on multiple fronts. First, by extending LICAP payments to all capacity suppliers the ISO-NE fails to target payments to encourage the specific conduct desired, which is the construction of new capacity, particularly in locations deficient in adequate capacity. The most reasonable cost basis for providing incentives to new entry is the minimum cost of ensuring that new resources are added to the system when and where they are needed, or a reasonable estimate thereof. Paying all capacity the same dollar amount (keeping in mind that this is an administratively set price, not an actual market price) and maintaining a sufficient level of payments for both new entrants and new units will yield unreasonable expenditures to be footed by consumers. The reality is that any artificially concocted market that results in compensating all capacity suppliers equally will either result in unreasonable rates or fail to compensate the specific resources that are needed or incented. Secondly, ISO-NE's price cap of 2.0 x EBCC is excessive and unreasonable. By Dr. Stoft's own

admission "Since a 30% return on equity is known to be **fabulous**, twice EBCC would stimulate more than enough investment, if it were assumed to persist indefinitely."[22] Again, it must be noted that this level of return is not obtained through a free market, it is obtained through an administratively set price. To the best of my knowledge, no regulated entity that has come either before the FERC or a public utility commission would be permitted such a return. Thus, without some form of public proceeding in which the usual standards for rates are applied, it can hardly be argued that this represents an appropriate application of standard ratemaking principles.

If you assume the 2 x EBCC revenue stream and discount the net revenue at an assumed rate of return of 12% over a 20-year period, the total return on investment is 259% *in excess* of the 12% annual return. Thirdly, ISO-NE's targeted level of excess capacity, set at a C_{Target} level of 5.8% above OC encourages an uneconomic excess of capacity. As shown above, ISO-NE's C_{Target} level equates to an LOLE of approximately 1 day in 75 years, or a level of reliability that is about seven and one half times greater than the NPCC standard. ISO-NE asserts that this target level is appropriate because it is the average level of excess capacity during that past twenty-one years. This profoundly unscientific approach to determining an optimal level of capacity fails to take into account that the majority of the past twenty-one years was spent in the era of vertical integration with its tendency to overbuild. Ironically, one of the primary reasons for deregulation was a desire on the part of policymakers to eliminate the

[22]ISO-NE Response to DENA/ISO-NE 14 (Responses to Duke Energy North America, LLC's Second Set of Data Requests to ISO New England Inc. provided by ISO-NE on October 1, 2004) (emphasis added).

uneconomic excess of capacity attributable to this era. The remainder of these 21 years came about after an overbuild of generation in New England that Dr. Stoft referred to as "stupid."[23] Also, ISO-NE's X-Intercept of 1.15 x OC is wholly inappropriate and fails to send proper signals for resource retirement when appropriate. Consider for a moment that based on ISO-NE's own analysis, 1.15 x OC represents an LOLE of 1 day in 1,250 years![24] Because of this X-Intercept point, the ISO-NE proposal would result in LICAP payments of $2.30/kw-month at IC/OC level of 1.12 x OC, which is equal to an LOLE of 1 day in 526 years.[25] To put this in its proper perspective, an inefficient generator that rarely produces energy could receive up to $27,600 per year per MW of installed capacity just to be available. Surely at an LOLE of 1 day in 526 years, the generator in this example should be sent a clear signal to retire.

Q. HAS ISO-NE'S PROPOSED APPROACH TO CAPACITY MARKETS BEEN PROVEN IN PRACTICE?

A. No it has not. By its own admission, ISO-NE's curve is experimental in nature.[26] There are parties who firmly believe that it will work – in theory. The ISO-NE proposal is intended to provide compensation to seldom run generators in load pockets (à la Devon, *et al*.), incent the development of new capacity resources when needed and allow the resource planning function to be assumed by the competitive market, all in one fell swoop. There is no market in existence where all of these functions have been addressed through a single mechanism. ISO-NE

[23] Stoft Deposition, Vol. 1 at 75:20.
[24] ISO Table 2.
[25] *Id*.
[26] Stoft Deposition, Vol. 1 at 121:19-21.

has adopted the "you can solve any problem if you throw enough money at it" approach in an attempt to force a single solution to work. Unfortunately, there are quite literally billions of dollars per year at stake in this case. Customers simply can't afford the price tag of ISO-NE's proposal when there is no hard evidence that it will work as planned. Even if the ISO-NE proposal does achieve all of its goals, it is highly improbable that it would do so in an efficient, least cost manner.

Q. DO YOU AGREE WITH ISO-NE'S ASSERTION THAT THE INCENTIVES IMPLICIT IN ITS "MARKET CONSTRUCTION" ARE NECESSARY TO INCENT INVESTMENT?

A. No I do not. ISO-NE asserts that a kinked curve with a steeper slope on the left side of the kink than on the right side is necessary to incent investment. By Dr. Stoft's own admission, "[t]he ability to forecast high prices accurately will send a strong investment signal before shortage conditions are realized."[27] Any downward sloping price curve will provide new entrants with the ability to forecast high prices with a reasonable level of accuracy. The impact of the price curve on future prices is quite transparent. Any event that would result in the shifting of the clearing price to the right side of the price curve, such as investment in transmission or generation, would have a fairly long lead time. By contrast, events that would potentially shift the price curve to the left, such as generator retirements, deactivations or extended outages could potentially occur with little or no notice. Thus, there is a disproportionate probability of unforeseen boom periods versus unforeseen bust periods for generation owners in any application of a downward sloping price curve. ISO-NE has asserted that at its

[27] Stoft Testimony at 17:3-5.

target level of 1.058 x OC, the actual level of capacity would fall below OC 15% of the time because that is what happened during the past twenty one years. This assertion is flawed because, as discussed by ISO-NE witness David LaPlante, "unusual"[28] nuclear outages were responsible for the actual level of capacity falling below OC in two of these three years.[29] Absent these "unusual" outages, actual capacity fell below OC in 1 out of 21, or 4.7% of occurrences.

Q. DOES THE ISO-NE LICAP PROPOSAL INCENT THE CONSTRUCTION OF NEW GENERATION?

A. The answer to this question is yes and no. The ISO-NE proposal creates such a massive windfall for capacity resource owners, that new entrants are certainly given a strong incentive to enter the fray. If a new capacity supplier joins the market and reduces the clearing price from say, 1.8 x EBCC to 1.3 x EBCC, they would still be earning revenues that exceed the benchmark frame unit by 30%. Since this new entrant did not previously own resources, the drop from 1.8 x EBCC to 1.3 x EBCC wouldn't be of consequence to it. The opposite applies to any capacity supplier that already owns resources within the pool. Due to the shape and application of ISO-NE's curve, any new capacity resource will significantly reduce revenues for existing resources. To put more flesh on this concept, I will use a real world example using the NEMA/Boston zone. Consider a capacity supplier that owns 1,000 MW of capacity in NEMA that is analyzing the impact of building a 170 MW frame unit as an addition to one of its existing sites in NEMA. Also for this example, let's assume that the level of capacity in

[28] LaPlante Deposition, Vol. 1 at 239:13.
[29] *Id*., Vol. 1 at 130: 9-12.

NEMA is such that the addition of the 170 MW unit will bring it to ISO-NE's C_{Target} of 1.058 x OC. The addition of this new resource would reduce the clearing price from about 10.80/kw-month to about $7.40/kw-month. This would mean a revenue reduction of about 1,000 MW x $3.40/kw-month x 1,000 (conversion to $/MW-month) x 12 months = $49 million per year for this capacity supplier's existing 1,000 MW. While this disincentive may be good for market power considerations by inadvertently preventing a greater concentration of resource ownership within LICAP zones, it has the unwanted effect of ensuring that enhancements to existing sites would be very unlikely to occur. Given that upgrades to existing sites are typically considered as being better than Greenfield development from a societal perspective, this is not a positive incentive.

Q. WOULD THE CONSTRUCTION OF NEW TRANSMISSION FACILITIES REDUCE LICAP COSTS UNDER ISO-NE'S PROPOSAL?

A. No, it does not. In some cases, the construction of new transmission facilities could actually increase LICAP costs under the ISO-NE proposal. A quick analysis of the 2005-2006 power year data demonstrates that the 345 kV transmission expansion being developed by NSTAR and Phase I of the Southwest CT Reliability Project could significantly increase overall LICAP costs. Here is why: by adding in the additional transmission capacity, the clearing prices between NEMA/SWCT and other zones will, absent the exercise of market power, converge. While this is very good for NEMA and SWCT customers, customers in the rest of New England would see their clearing prices increase because more capacity in other LICAP regions will be able to be used to reduce

the local sourcing requirement in NEMA and SWCT. The decrease in NEMA and SWCT clearing prices would impact fewer megawatts of capacity than the increase to rest of pool and Maine clearing prices. Based on 2005-2006 power year data, the transmission expansions would result in a single year net increase in system wide LICAP costs of about $42 million. This is a situation that aptly defines the term "perverse consequence." Table 6 illustrates the impact on each LICAP region.

Table 6

Price Impact of Near Term Transmission Upgrades (2005 – 2006 Data)

w/ 345 kV & Phase I	NEMA	ROP	ME	ROCT	SWCT	Pool
Clearing ($/kW-month)	$2.05	$2.05	$2.05	$4.34	$4.34	
Net Cost Impact ($M)	$28	$150	$25	$30	$93	$326
Additional cost to Base Case	-$8	$19	$4	$40	-$13	$42

Therefore, an investment of hundreds of millions of dollars in transmission upgrades could result in prices for customers in New England increasing by $42 million per year. Obviously, this is a significant flaw in the ISO-NE proposal

Q. IS ISO-NE'S CALCULATION OF EBCC REASONABLE?

A. It appears that ISO-NE witness, Mr. Reed, has overestimated the total cost of new entry in two ways, as follows: first, Mr. Reed did not appear to net out any estimates of Residual Credits or Salvage Credits which could be applied against the investment recovery needed for his choice of resource. For example, Residual Credits at the end of the unit's life might include value associated with land, transmission interconnection(s), and/or site permits. Also, Salvage Credits might

include plant equipment with potential resale value in excess of their value in the used-equipment market. Second, Mr. Reed assumed the peaking resource would be a dual-fueled unit. Mr. Reed states: "While there can be a case made for eliminating either (dual fuel or SCR) based on a pure capacity focus, I concluded that I would be ignoring actual costs that will be incurred when installing new generation, and that excluding those costs would understate the cost of capacity that would actually be built."[30] In counter-point, given that the capacity focus in the LICAP proposal is that of a peaking resource, which by definition is targeted for low capacity-factor operation, it is not appropriate to add the costs of a back-up natural gas fuel supply to its new-entry total cost. For example, it is unlikely that such a back-up for a peaking unit would have had any significant value during the New England Cold Snap event of January 14-16, 2004 since many units declared themselves unavailable due to natural gas unavailability. Having natural gas capability might actually prevent units from running during extreme cold conditions since many generating units are permitted to burn oil only if gas is physically unavailable which in the gas industry is a condition they seek to avoid at all costs. So although gas may be physically available, units will declare themselves unavailable due to the high cost penalties for taking the gas. Furthermore, the inappropriateness of Mr. Reed's assumption is particularly underscored by contrasting it with the reality of actual market experience in New England since competitive markets began in 1999: the overwhelming majority (nearly 8,000 MW) of large new combined-cycle resources (that is, resources

[30] Reed Testimony at 17:5-8 (emphasis added).

which, unlike peaking resources, are intended for intermediate and base-load operation) to come on-line in New England have not been dual-fueled facilities.[31]

Q. IS "AS-IS" BETTER THAN "AT CRITERIA" FOR DETERMINING LOCAL SOURCING REQUIREMENTS?

A. Yes it is. I fully support ISO-NE's use of the as-is standard. As-is recognizes both the excess capacity that exists in the pool and the pool planning process that has been in place for decades. The historical and current state of NEPOOL is an integrated system in which certain sub-zones rely on other sub-zones. More specifically, the as-is methodology of calculating local sourcing requirements allows resources from some sub-regions to be depended upon to serve load in other sub-regions as long as 1) there is sufficient transmission capability into the load zone, and 2) such dependence doesn't reduce the source zone's reliability to a level below the 1 day in 10 year LOLE standard. The at-criteria methodology that was included in ISO-NE's March 1 Filing fails to recognize the benefits of pooling and excess capacity and was appropriately discarded by ISO-NE in its August 31 Filing.

Q. PLEASE DESCRIBE THE IMPORTANCE OF OBJECTIVE CAPABILITY TO ISO-NE'S LICAP PROPOSAL?

A. The Objective Capability, or OC, is probably the most critical input to ISO-NE's LICAP clearing price calculation. For illustrative purposes, suppose that ISO-NE determined that the OC for NEPOOL was to be increased by 1,000 MW. Using

[31] *See* "Final Report on Electricity Supply Conditions in New England During the January 14 – 16, 2004 Cold Snap," by ISO-NE Market Monitoring Department, dated October 12, 2004 at page 19, footnote 23. Available at http://www.iso-ne.com/special_studies/January_14_-_16_2004_Cold_Snap_Reports/1_Final_Report_On_January_2004_Cold_Snap.pdf

2005/2006 power year data, a 1,000 MW increase to OC would result in a $992 million increase in annual LICAP costs. In a situation where the actual level of capacity was at less than ISO-NE's Ck point on the price curve, the magnitude of a 1,000 MW increase to OC could cost in excess of $2 billion per year. This illustrates just how sensitive LICAP prices are to such changes. This 1,000 MW example was not pulled out of thin air. There have been recent discussions at NEPOOL where some parties have advocated that the load forecasting methodology used in the OC calculation be changed in a manner that would increase OC by more than 1,000 MW, possibly as much as 1,600 MW. These discussions have taken place even though the current load forecasting methodology has been in place since at least the late 1980's and, to my knowledge, has not resulted in a single incident where load was lost due to insufficient resources. It must be noted further that the ISO-NE proposal would provide a strong incentive for certain NEPOOL voting sectors to always push for an increase in OC, regardless of whether such increases are needed for reliability due to the potentially massive financial gains that would result from such an increase. This could serve to invalidate any stakeholder process that is used to decide upon future changes to the methodology for determining OC.

Q. HOW WOULD YOU PROPOSE THAT FUTURE CHANGES TO OC BE ADDRESSED?

A. Given the magnitude of dollars at stake, it is my recommendation that any significant change to OC require FERC approval as a change in rates. ISO-NE has contended in various objections to data requests that the determination of OC

is not an issue that has been set for hearing in the case. The reality of the situation is that this is a rate case, and any change to OC would amount to a significant change in rates. ISO-NE cannot be granted the right to change rates by billions of dollars per year without due process being granted to the parties paying such rates. My suggestion here is further refined by adding the concept that ISO-NE should have the right to make reasonable changes to OC that parallel actual load growth by making an annual filing at FERC. Stakeholders would, of course, have the right to intervene or protest such filings. My concern is related more to changes in the methodology used by ISO-NE to calculate OC than changes in OC that occur during the normal course of load growth.

Q. IS ISO-NE'S PROPOSAL TO SUBTRACT INFRA-MARGINAL RENTS FROM LICAP CLEARING PRICES REASONABLE?

A. My answer is yes and no. ISO-NE's decision to subtract the actual infra-marginal rents attributable to the benchmark unit is a significant change in a positive direction. This change recognizes that energy and capacity markets are intertwined. The change also provides the correct incentive towards generator efficiency. An actual generator that runs more efficiently than the benchmark unit will see upside revenue as a result of this crediting mechanism whereas less efficient units will not. Unfortunately, ISO-NE did not follow through and recognize that there are significant infra-marginal rents in addition to *energy market* infra-marginal rents. There is a fairly long laundry list of current and planned infra-marginal rents that ISO-NE has not put forward in its proposal for inclusion. Among these are revenues from automatic generation control, forward

reserves, VAR support, black starts and other ancillary services intended for implementation prior to or immediately after the LICAP implementation date (such as, locational forward reserves). If these revenues are ignored by ISO-NE's calculation of infra-marginal rents, they become sources of excess income being received by capacity resources.

Q. PLEASE DISCUSS ISO-NE'S METHODOLOGY FOR CALCULATING CRITICAL HOURS AND RESOURCE AVAILABILITY.

A. ISO-NE's proposal to include an adjustment to the LICAP revenue of capacity suppliers based on availability during critical hours is a very positive development. In January 2004, it became very clear that payments for availability are necessary when thousands of megawatts of gas-fired capacity became unavailable in critical hours due to and the declaration by generators that fuel was unavailable. Additionally, the proposed methodology that is set forth in ISO-NE's response to discovery requests SUPPLIERS/ISO-NE 3 (submitted on October 2, 2004) and Staff/ISO-NE 4-13 (submitted on October 8, 2004) fixes many of the deficiencies that were present in Dr. Stoft's testimony regarding this concept. The reason that this concept is a positive development is that it ties performance to payment. The performance for payment concept will affect the behavior of capacity resources in a manner that preserves the reliability of the power grid. Absent a linkage to performance, the buyers of capacity would be receiving exactly nothing in return for their payments.

Q. PLEASE EXPLAIN THE "LOAD SWAP" ISSUE AND ITS IMPORTANCE TO THE DEVELOPMENT OF PROPER LOCAL SOURCING REQUIREMENTS.

A. As described by Mr. Salamone in his testimony, the NEMA Load Swap is a real NEMA resource that can be relied upon during the "Critical Hours" defined in ISO-NE's proposal. ISO-NE should be directed to include the NEMA Load Swap in its local sourcing requirement calculations for NEMA. The impact of including the NEMA Load Swap would be a 50 MW reduction in the NEMA local sourcing requirement. Using the 2005/06 power year in ISO-NE's filing, the change would bring NEMA and rest of pool clearing prices into equilibrium at approximately $2.10/kw-month.

Q. WHAT IS THE ROLE OF CAPACITY TRANSFER RIGHTS IN THE ISO-NE PROPOSAL?

A. Per ISO-NE's description, a Capacity Transfer Right ("CTR") is a financial instrument that allows a load serving entity to import ICAP from a neighboring ICAP region to meet a portion of its local capacity purchase obligation. The total quantity of CTRs for a given transmission interface is equal to the Capacity Transfer Limit ("CTL") for that interface. In the ISO-NE August 31 Filing, CTRs are allocated to load serving entities on a pro-rata basis. ISO-NE witness Mark Karl states that "[t]he New England design explicitly identifies, tracks and settles CTRs only to provide a means of accommodating non-uniform, or preferential allocations of the ability to import capacity to a Locational ICAP Region."[32]

[32] Karl Testimony at 11:15-17.

Since ISO-NE does not propose a preferential allocation of CTRs, the CTRs have no discernable function whatsoever.

Q. SHOULD CAPACITY TRANSFER RIGHTS EXIST AT ALL?

A. No. ISO-NE erred by including CTRs in both its March 1, 2004 and August 31, 2004 proposals. The only apparent reason to create CTRs would be to allocate them disproportionately to some entities versus others. In its June 2 Order, FERC rightly stated that "Capacity Transfer Rights should be allocated in a way that allows the benefits of Capacity Transfer Rights to be received by those who ultimately pay the costs of the transmission system."[33] The key concept is that the cost of the transmission system is paid by the customers of transmission owners through retail rates and therefore the benefits of the transmission system should be allocated to those who paid for the transmission system. In NEPOOL, all load has paid equally for transmission facilities for many years. If all load is treated equally with respect to its obligation to pay for the transmission system, all load must be treated equally with regard to the benefit of that system. If this cost/benefit doctrine is intended to be followed, then there is no valid reason for CTRs to exist.

IV. <u>The Coalition LICAP Incentive Plan and Price Curve</u>

Q. DO YOU HAVE AN ALTERNATIVE PLAN TO PROPOSE IN PLACE OF ISO-NE'S LICAP PROPOSAL?

A. Yes I do. The Coalition has developed an alternative proposal that addresses the fatal flaws of ISO-NE's proposal while retaining the overall concept of a downward sloping price curve.

[33] June 2 Order at P66.

Q. WHAT IS THE PURPOSE OF THE COALITION LICAP PROPOSAL?

A. The Coalition proposal has been designed to provide appropriate incentives to economic investment in capacity serving resources only when such resources are required. As discussed above, the ISO-NE proposal encourages both the construction of resources in excess of those needed for reliability and the continued existence of resources that should be given a clear signal to retire. Just as importantly, the Coalition LICAP proposal has been designed to achieve its investment incentive goals while also meeting the just and reasonable rate standard set forth in the Federal Power Act.

Q. PLEASE EXPLAIN HOW THE COALITION PROPOSAL WORKS.

A. The Coalition LICAP proposal specifically targets new resources with incentive capacity revenue instead of paying all existing resources. By streaming LICAP payments directly to the parties that are being incented, the massive overpayment that exists in the ISO-NE proposal is avoided. The cost to consumers of new entry will approximate the actual cost of rational new entry. This accords with standard rate making principals. Another significant feature of the Coalition proposal is the design of its price curve. As described in more detail below, the Coalition price curve is designed to encourage only rational investment in contrast to the ISO-NE curve, which was designed to encourage an uneconomic excess of capacity. Finally, the Coalition proposal includes RMR contracts until they are no longer necessary. The Coalition recognizes that there may be interim periods of time where certain units have to remain connected to the grid even though the market has given them a clear signal to retire. In these instances, the cost of unit

specific RMR contracts is the highest possible just and reasonable cost for the required reliability.

Q. HOW ARE EXISTING CAPACITY RESOURCES TREATED UNDER THE COALITION LICAP PROPOSAL?

A. Under the Coalition LICAP proposal, the existing ICAP market would continue as-is. Existing resources would continue to operate under the market structure that existed before LICAP. For many capacity resources, this is the market structure that was in place during their development phase. Existing capacity resources that are needed to provide either capacity of operating reserves in specific locations would continue to be eligible for RMR contracts. Existing capacity resources that are not needed for reliability would not be eligible for any subsidization beyond their market revenues.

Q. ISN'T THE COALITION LICAP PROPOSAL UNFAIR TO EXISTING CAPACITY RESOURCES?

A. I do not believe that it is unfair to existing resources. The Coalition LICAP proposal does not take anything away from existing resources. First, all of the existing ICAP resources in New England have applied for, and have received, market-based rate authority. By necessity, they have accepted the risk that the market will not fully compensate them for fixed costs during certain periods in return for collecting prices well in excess of total average costs in flush periods. By contrast, the ISO-NE LICAP proposal removes the downside risk, at the expense of consumers, while retaining the generators' upside, again to the detriment of consumers. Second, Dr. Stoft states that "[a]ny time there are sunk

costs, they can be taken if they are not legally protected, because the market cannot protect them."[34] This statement is, of course, unsupported. Nevertheless, the Coalition LICAP Proposal retains the existing ICAP market, therefore sunk costs are not "taken" from existing resources. If the market projections that were made by developers or buyers of generation were much higher than the prices that actually resulted in the market, that is a risk that these entities agreed to bear when they made their investment decisions. The reality of any unregulated market is that sometimes prices do not meet projections, particularly in times of oversupply as is the current situation in New England. Other types of businesses deal with this on a daily basis. The New England energy market is not a welfare state and there is no legitimate reason to require consumers to provide a bail out of the bad investment decisions made by others.

Q. WHAT DO YOU UNDERSTAND THE PURPOSE OF LICAP TO BE?

A. Between the FERC and ISO-NE, I discern two legitimate objectives. First, according to FERC, LICAP is required to address the need to compensate resources that are seldom run but are needed for reliability. Second, according to ISO-NE, LICAP is intended to incent the construction of new capacity into areas that are, or imminently will be, deficient in capacity. As stated in the March 22, 2004 protest by members of this Coalition and other parties, the first objective is more appropriately solved through a market or administrative solution which encourages the construction and/or maintenance of local operating reserves.[35] It is important to note that ISO-NE has already presented its concept of a local

[34] Stoft Testimony at 103:14-15.
[35] *See e.g.*, Protest Regarding Filing of ISO New England Inc. and Alternative Proposal for an Installed Capacity Market by Attorney General of Massachusetts, *et al*. at 29.

operating reserve market to NEPOOL stakeholders, as a new product that is incremental to LICAP. If local operating reserves are to be addressed through this new stakeholder process, only the second of the objectives listed above needs to be considered - that objective being to provide appropriate incentives to new capacity additions where needed.

Q. WOULD THERE BE CIRCUMSTANCES WHERE EXISTING UNITS COULD QUALIFY FOR LICAP PAYMENTS UNDER THE COALITION LICAP PROPOSAL?

A. Yes. As LICAP market rules are developed, it will be necessary to define what constitutes a new capacity resource. Offering a detailed definition now is somewhat beyond the intended scope of my testimony, other than to suggest that the definition of "new capacity resources" should be prudently developed via a stakeholder process. A reasonable categorization of new capacity resources could include the following: 1) New construction where ground-breaking begins after the date of an initial FERC order approving the Coalition LICAP proposal ("Order Date"); 2) Incremental rating increase or re-powering where construction begins after the Order Date; 3) Reactivation of retired capacity that had retired prior to the Order Date; and 4) New real-time demonstrated demand response implemented after the Order Date which is under the control of ISO-NE.

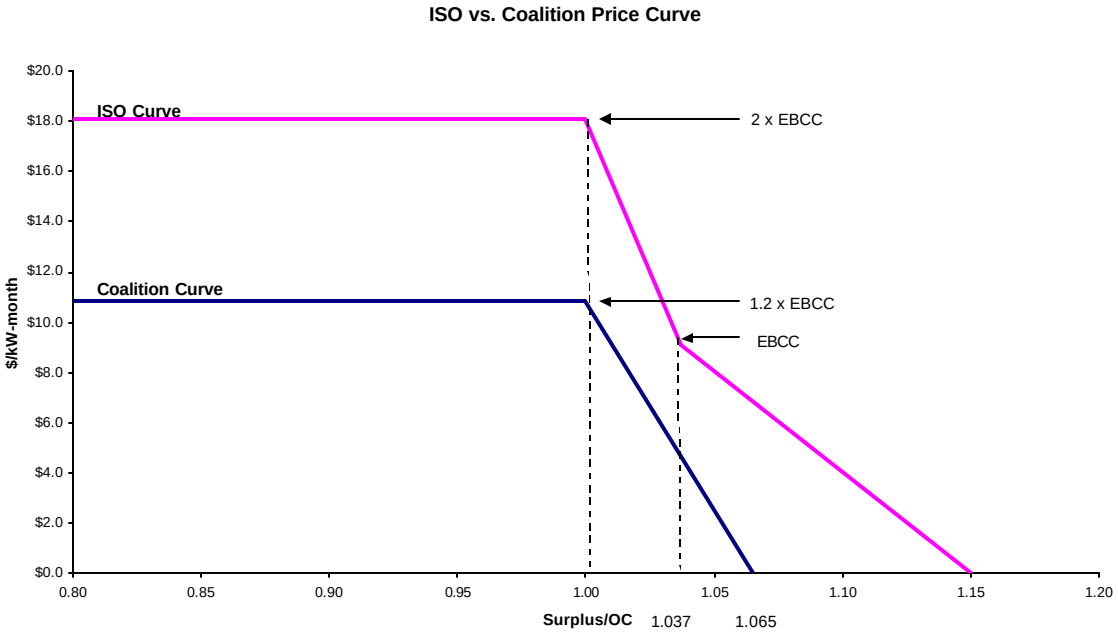
Q. ARE RMR CONTRACTS APPROPRIATE SOLUTIONS TO TEMPORARY RELIABILITY PROBLEMS?

A. Yes. Paying all capacity resources in a particular zone to solve a reliability problem that can be solved by a single unit results in excessive payments beyond -

what can be construed as reasonable. In a perfect world, there would be no need for unit-specific contracts. The power grid is not perfect, however. Its evolution over decades of cost of service regulation has resulted in the existence of a few locales where certain resources are needed for reliability until planned transmission upgrades are complete or until the planned locational forward reserve market results in the construction of replacement resources. Making LICAP payments to all resources within a region to solve a local reliability problem will not accomplish anything. In this case, the incented behavior is the provision of local reliability by one or more specific resources that are uniquely situated. The only just and reasonable incentive rate is that which is paid to the specific resource(s) providing a solution to the local problem.

Q. WHAT ARE THE PARAMETERS OF THE DOWNWARD SLOPING CURVE PROPOSED BY THE COALITION?

A. The Coalition LICAP proposal includes a downward sloping price curve that crosses OC at 1.2 x EBCC and intersects the x-axis at a point that results in an LOLE of 0.01 or 1 day in 100 years. For purposes of this discussion, I will use 1.065 x OC as a proxy since that number represents an LOLE of 0.01 pool-wide. The 1.2 x EBCC crossing point also serves as a cap. Below is a picture of the Coalition curve along with the curve proposed by ISO-NE.



Q. WHY DID THE COALITION SELECT 1.2 x EBCC AS ITS POINT OF INTERSECTION WITH OC AND AS A CAP?

A. As previously discussed, the goal of the Coalition's LICAP proposal is to encourage economic investment and discourage investment that would lead to an uneconomic excess of capacity resources. The selection of 1.2 x EBCC was chosen for a few reasons. First of all, the Coalition recognizes that there may be periods of time when new entrants are unable to earn a reasonable return. Because of this, there should be corresponding periods of time where they are allowed to realize excess returns. Where the coalition differs drastically from ISO-NE is in the range of reasonableness of these excess returns. Whereas Dr. Stoft has advocated that returns in excess of 30% are reasonable, the Coalition chooses to adopt a more conservative approach to determining what defines a reasonable return. In his testimony, ISO-NE witness John Reed states that "[f]or

uncontracted merchant capacity, investors typically target a 15% to 17% after-tax return on equity based on the perceived high risks of cost recovery in today's electric market."[36] The Coalition estimates that 1.2 x EBCC represents a 15% to 17% after-tax return on equity. If this return on equity is sufficient for investment without assurance of cost recovery, then it should provide sufficient boom-year upside for capacity resources that are receiving a certain level of comfort regarding cost recovery. Simply put, a moderate amount of upside will encourage rational investment. An excessive amount of upside, as proposed by ISO-NE, will encourage an excess of investment. Consider the following numbers: the OC of NEPOOL is approximately 30,000 MW. A single percent of OC is 300 MW, or almost twice the size of Mr. Reed's reference 170 MW frame unit. The Coalition's proposed curve would pay new entrants 1.0 x EBCC if the installed capacity/OC is equal to 1.01, or 1% above OC. At 2% above OC, the loss of load expectancy is 1 day in 20 years, or twice the NPCC standard. At this point, there would be approximately 600 MW of excess capacity in the pool and new entrants would receive approximately 0.8 x EBCC. This level is high enough to provide coverage of debt and operating costs, while still providing a small return. This is an appropriate level because at 2% above OC, the excess reliability is not necessary and should not be encouraged. As previously mentioned, the price curve is transparent. Entities making investment decisions will be able to accurately forecast the impact of those decisions and time the new entry accordingly.

[36] Reed Testimony at 28:17-19.

Q. WHY DID THE COALITION SELECT AN LOLE OF 0.01 AS ITS X-INTERCEPT POINT?

A. It is simply not reasonable to expect the buyers of capacity to support a level of reliability beyond that which exceeds the NPCC standard of 0.1 by a factor of ten. At this point, a clear signal has to be sent to developers that their projects are not needed and should not move forward unless such projects include the retirement of less efficient resources.

Q. WHY WON'T THE STEEPNESS OF THE COALITION CURVE RESULT IN INADEQUATE NEW ENTRY?

A. There are a few key points regarding price curve design where the Coalition's viewpoint differs substantially from that of ISO-NE. All of these points have been mentioned already in this testimony, but it is useful to summarize them here. First of all, the price curve is very transparent, therefore entrants will be able to predict the impact that their new entry will have on prices with a fair amount of accuracy. Events that would drive the clearing price to the right side of the price curve will generally have long lead times and be foreseeable. At the same time, events that would drive clearing prices to the left side of the price curve may sometimes occur very quickly which could result in earnings above the 1.0 x EBCC level for periods of time. The second point is that EBCC itself is based on a certain reference unit. Any new entrant that operates more efficiently than the reference unit will always have the opportunity to earn returns on infra-marginal rents that exceed the reduction in their LICAP payment that is due to the infra-marginal rents attributable to the reference unit. Finally, the Coalition price curve

differs drastically from the ISO-NE price curve because it is targeted at a different goal. The Coalition price curve does not seek to maintain the uneconomic excess of capacity that exists today. Rather, it is designed to encourage rational investment when needed while maintaining just and reasonable rates.

Q. WHAT IMPACT WILL THE COALITION PROPOSAL HAVE ON NEW ENTRANTS THAT HAVE DIFFERENT COST STRUCTURES THAN THE REFERENCE UNIT?

A. Actual unit cost structures will vary. Units that are more efficient than the benchmark unit will earn better returns, while less efficient units will earn lower returns. It is wholly appropriate for more cost efficient entrants to earn stronger returns while less cost efficient entrants earn subnormal returns. For this reason, the use of a benchmark unit is a very good concept. Additionally, this incentive for efficiency could have other positive impacts for NEPOOL related to lower fuel use and lower emissions.

Q. HOW LONG WILL NEW ENTRANTS QUALIFY FOR LICAP PAYMENTS UNDER THE COALITION PROPOSAL?

A. The Coalition plan allows new entrants to earn LICAP incentive revenue for twenty years if they remain active. The decision to allow twenty years of recovery is based partly on the testimony of John Reed. In his testimony, Mr. Reed uses a twenty year investment horizon.[37] In general, informal discussions that I have had with developers and financiers over the past few years have generally indicated that twenty year investment horizons and debt amortization schedules are commonly used for the financing of merchant generation. Also, the

[37] Reed Testimony at 27:21-22 and 28:1-2.

Coalition believes that it is reasonable to have the duration of the LICAP incentive parallel the investment timeline used in the calculation of the EBCC to closely match the incentive to the desired behavior.

V. Criteria for Establishing LICAP Zones

Q. PLEASE DISCUSS ISO-NE'S CRITERIA FOR DETERMINING WHICH SUB-REGIONS QUALIFY AS LICAP REGIONS.

A. To date, ISO-NE has not provided specific calculations that it would use as criteria for developing LICAP zones. In its March 1 Filing, the ISO-NE stated that its designation of LICAP zones was "based on the currently defined Load Zones in the NEPOOL Control Area."[38] In a February 3, 2004 letter from Mr. Peter Wong of ISO-NE to Mr. Thomas Murrell of NSTAR, a definition of ICAP regions was provided: "ICAP Regions are geographic areas for which the ISO determines that the incremental/decremental reliability impacts associated with additions/reductions of ICAP Resources are likely to differ significantly from other geographic areas of the NEPOOL Control Area. Differences in reliability may result from transmission limitations creating an inability to import or export capacity to or from ICAP Regions under certain high load conditions."[39] Conspicuously absent from this definition is any mention of the actual measure of reliability in an ICAP region and its obvious application as a sanity check. For example, a zone that has an LOLE of .0063, or 1 day in 159 years may exhibit significantly different reliability impacts from additions or reductions, as described above, from those of a zone that has an LOLE of 0.0008, or 1 day in

[38] ISO-NE March 1 Filing, Transmittal letter at 5 (footnote omitted).
[39] Letter from Peter Wong of ISO-NE to Thomas Murrell of NSTAR dated February 3, 2004, at 1.

1,250 years. Nonetheless, the reliability of the first zone still exceeds the NPCC standard by a significant measure. If after the additions or reductions in question, the LOLE of the zone in question would still exceed NPCC standards, there would be no compelling reason to designate the zone as being a LICAP region. The relative level of reliability when compared to another geographic area should be rendered irrelevant if both areas are exceptionally reliable. As I discuss later in my testimony, the potential damage from establishing LICAP regions outweighs any benefits gained when reliability concerns are low.

Q. DID ISO-NE TAKE NEAR-TERM UPGRADES TO THE TRANSMISSION SYSTEM INTO ACCOUNT IN ITS DEVELOPMENT OF LICAP ZONES?

A. No, ISO-NE has not, even though the NSTAR 345 kV expansion of transmission capacity into NEMA will be in service six months into LICAP regime as testified to by Charles Salamone. I would note that in its June 2 Order, the Commission deferred the effective date of LICAP in order, among other things, to allow for completion of needed infrastructure upgrades in New England's constrained areas. The ISO-NE apparently has no plan to reconsider LICAP designations based upon completion of transmission enhancement, no matter what their size or impact.

Q. WHAT ARE THE PROPER CRITERIA TO EMPLOY WHEN DEVELOPING LICAP REGIONS?

A. LOLE is the only sufficient measurement that can be used to determining the creation or elimination of LICAP zones. The entire point of a LICAP scheme is to preserve reliability and LOLE is the NPCC accepted standard of measurement

for reliability. As previously mentioned, the NPCC LOLE standard is 0.1 or 1 day in 10 years. Any criteria for establishing LICAP regions should be based on preserving a 0.1 LOLE. The criteria set forth by ISO-NE in its definition of ICAP regions, as shown above, fail to recognize that differing levels of reliability between geographic areas is not an issue unless one of the geographic areas is in danger of having its LOLE rise above 0.1.

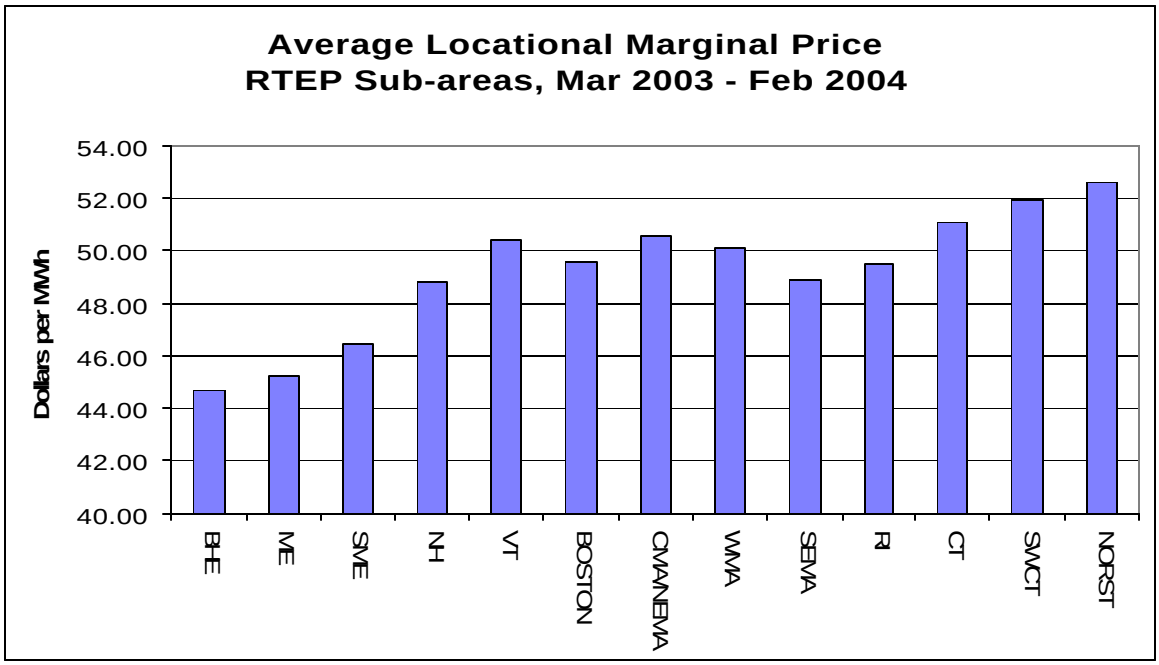
Q. SHOULD THE DIVERGENCE OR CONVERGENCE OF CONGESTION PRICING BE CONSIDERED?

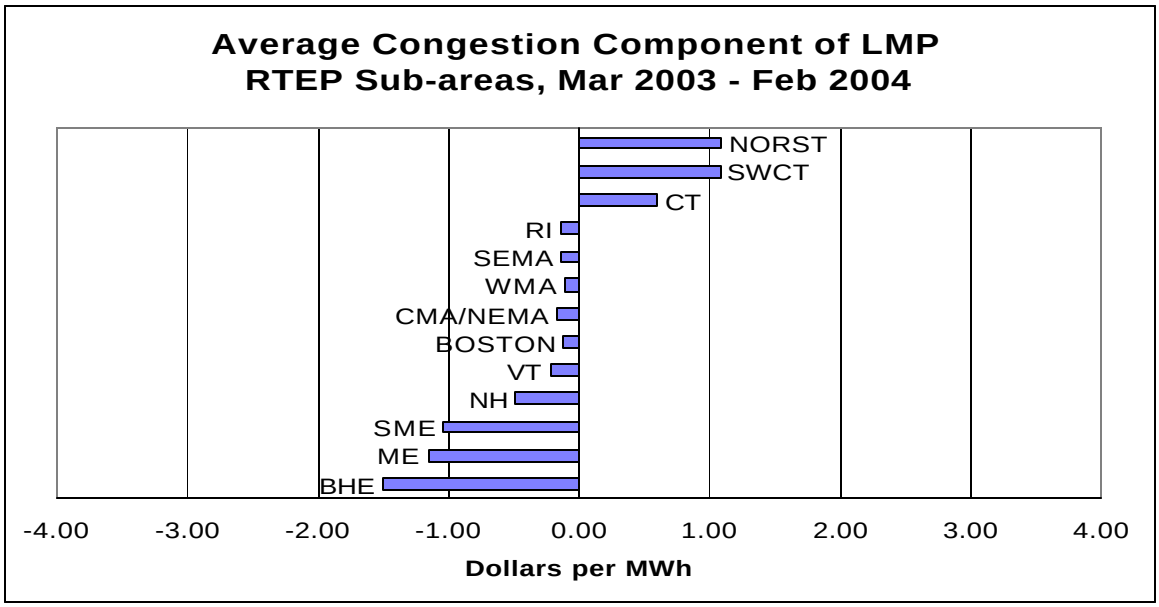
A. Cost divergence and convergence provides a useful look at inter-zonal relationships including the relative balance of supply and demand. However, congestion pricing falls short if it used as a sole criterion for the establishment of LICAP zones. There are a variety of other factors that could affect price differentials such as generator efficiency and bidding behavior within zones. As a secondary criteria, congestion and locational marginal pricing (LMP) differentials are a very useful indicator.

Q. GIVEN THE ABOVE, IF THE DIVERGENCE OR CONVERGENCE OF CONGESTION PRICING WERE DEEMED RELEVANT, WOULD SUCH AN ANALYSIS DEMONSTRATE THAT NEMA/BOSTON SHOULD QUALIFY AS A LICAP ZONE?

A. Currently, NEMA exhibits no reasonable price divergence from the regions that are included within the rest of pool zone by ISO-NE. Below are excerpted tables from ISO-NE's own TEAC 23 Presentation on June 25, 2004. These tables clearly show that LMPs and congestion charges for the NEMA/Boston zone have

been fundamentally similar to rest of pool zones since the implementation of Standard Market Design in 2003.





Q. DOES THE COALITION HAVE HARD DATA THAT SUPPORTS ITS CASE WITH REGARDS TO THE LOLE OF NEMA?

A. There is a wealth of information available that supports the Coalition's case. The following data is from the Regional Transmission Expansion Plan (RTEP) produced by ISO-NE. The most recent version of this plan is designated as RTEP04. Contained in Section 6.2 of the RTEP04 draft are twelve scenarios that assume different levels of investment in transmission and different generation retirements. In addition to RTEP04, there is useful information regarding the LOLE of NEMA in the aforementioned TEAC presentation, some of which has been incorporated into my testimony.

Q. WHAT DOES THIS DATA SAY ABOUT THE LOLE OF NEMA?

A. Of the twelve cases that are detailed in RTEP04, only one sensitivity case results in an LOLE (in study year 2013) worse than 1 day in 10 years for NEMA/Boston. This sensitivity case assumes the retirement of New Boston Unit 1 and Salem Harbor Units 1-4 and also assumes that the NSTAR 345 kV transmission upgrade is not completed. This is a highly unlikely scenario. As stated in Mr. Salamone's testimony, NSTAR's development of the NSTAR 345kV project has been progressing on schedule and there is no reason to believe that it will not happen. In another case in which ISO-NE assumed the same retirements but included the 345 kV upgrade, NEMA/Boston maintains a level of reliability that was better than 1 day in 10 years until 2013. Below are a few tables of LOLE data for NEMA from RTEP04 under various scenarios.

Table 3
Base Case with NSTAR 345 kV Transmission Upgrade
SWCT Reliability Project Phase I and II
And Northeast Reliability Interconnect Project

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
LOLE (1)	0.001	0.001	0	0	0	0	0	0	0.001	0.002
LOLE (2)	1,000	1,000	> 1,000	> 1,000	> 1,000	> 1,000	> 1,000	> 1,000	1,000	500

Table 4
Base Case with NSTAR 345 kV Transmission Upgrade,
SWCT Reliability Project Phase I and II
And Retirement of New Boston 1 and Salem Harbor 1–4

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
LOLE (1)	0.124	0.112	0.002	0.005	0.006	0.008	0.014	0.023	0.04	0.048
LOLE (2)	8	9	500	200	167	125	71	43	25	21

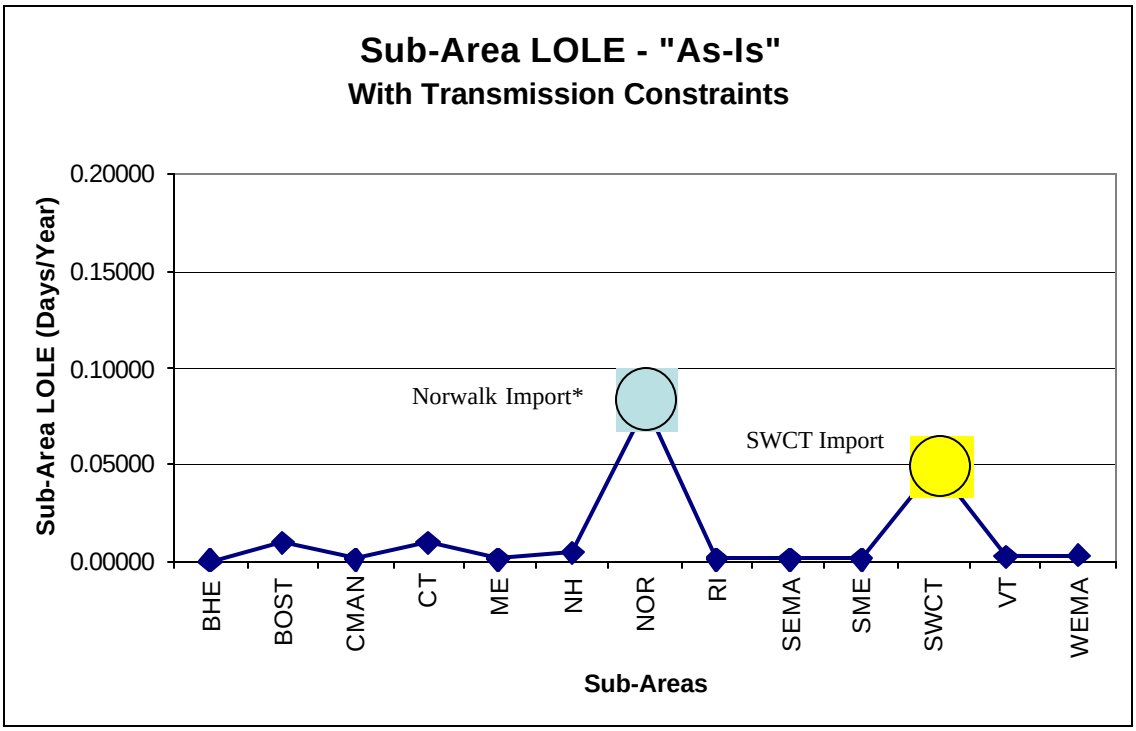
Table 5
Base Case with NSTAR 345 kV Transmission Upgrade,
SWCT Reliability Project Phase I and II
And Retirement of New Boston 1, Salem Harbor 1–4, Kendall 1-3 and Devon 7 & 8

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
LOLE (1)	0.42	0.368	0.011	0.015	0.022	0.029	0.032	0.057	0.085	0.102
LOLE (2)	2	3	91	67	45	34	31	18	12	10

(1) LOLE expressed as a probability for loss of load in a year
(2) LOLE expressed in terms of 1 day in "x" number of years loss of load expectancy

As can be seen above, even assuming significant retirements NEMA/Boston remains well within the NPCC standard of 1 day in 10 years LOLE for several years once the NSTAR 345 kV upgrade is placed into service in 2006. This level of reliability is maintained until 2013 even with the assumption of several generator retirements and no capacity additions as shown in Table 5. Also, the table inserted below is from an ISO-NE presentation called "Review of Locational ICAP Methodology" dated January 15, 2004. This presentation

clearly demonstrates that NEMA's LOLE is significantly better than the NPCC



standard of 0.1.

The evidence clearly demonstrates that under any reasonable criteria, NEMA/Boston does not qualify as a LICAP region.

Q. DOES NEPOOL SUFFER FROM A SYSTEMIC DEFICIENCY IN CAPACITY?

A. No. NEMA currently is characterized as having surplus capacity. As set forth in Mr. LaPlante's testimony, peak load in NEMA is about 5200 MW, current transmission capacity is 3600 MW and indigenous resources are 3430 MW.[40] Hence, there are 7030 MW of capacity potentially available to meet a 5200 MW load, which translates into an excess of 1830 MW.

[40] LaPlante Testimony at 43, Table 6.

Q. DOES THE ISO-NE ALLEGE THAT NEMA IS DEFICIENT IN CAPACITY?

A. No. The ISO-NE performs a sophisticated series of modeling that simultaneously ratchets down available capacity until resources otherwise available in the pool at large are insufficient to be accessed by a local region. This process leads to the establishment of the amount of capacity that the ISO-NE deems to be necessary within a zone in the event of extreme circumstances. From NEMA, this Local Sourcing Requirement is 2733 MW. Local resources in NEMA are 3430 MW. Hence, the ISO-NE has not proven that LICAP is necessary to incent additional resources into NEMA.

Q. COULD DESIGNATING NEMA AS A LICAP ZONE BE POTENTIALLY HARMFUL TO CONSUMERS?

A. Yes. Despite late breaking changes to ISO-NE's proposal, significant market power issues remain. For NEMA, or any other zone that is smaller than the pool as a whole, a single event of market power abuse will naturally cause a greater level of damage because the shift in the clearing price on the price curve will be magnified. For the following example, assume that both NEMA and Rest-of-Pool have an IC/OC of 1.12 (or 12% excess capacity above OC). The removal of 300 MW from NEMA will shift the clearing price from approximately $2.40/kw-month to about $6.40/kw-month. The same 300 MW withholding would shift the rest of pool clearing price from approximately $2.30/kw-month to about $4.00/kw-month. It is quite obvious that fewer zones are better. As I will detail later in my testimony, even with various improvements that ISO-NE has proposed

to add to its LICAP scheme, there are ways that capacity may be withheld to significantly drive up prices.

Q. DOES THIS ISSUE EXTEND BEYOND THE NEMA SUB-ZONE?

A. Yes it does. One issue that has been somewhat lost in the shuffle is that ISO-NE has implicitly claimed the right to declare sub-zones to be LICAP regions without stakeholder or FERC oversight. One problem with a LICAP concept in general is that it balkanizes the NEPOOL region. There may be cases where significant differences in reliability in different sub-regions makes this justifiable, but justification for such cases should not be subjective in nature. Any case for creating or retaining LICAP zones should be a well-defined mathematical analysis with specific criteria. These specific criteria should be based entirely on the preservation of an LOLE of no more than 0.1. The overall goal should be to minimize balkanization and operate New England as an integrated pool whenever possible. In their October 18, 2004 Answer to Motions to Compel, the Capacity Suppliers allege that "[t]here is, moreover, no potential harm to Movants if a NEMA zone turns out to be unnecessary."[41] The Capacity Suppliers are missing the real point, which is that the existence of a LICAP zone should be a response to a specific problem - for the duration of that problem. The default scenario should be no LICAP zones if there are no specific capacity deficiency concerns. If the default scenario were to include LICAP zones when not needed, then every load zone in New England would be a separate LICAP zone. The Capacity Suppliers also allege that "[m]oreover, since ISO-NE now plans to ignore supplier bids to set LICAP prices, there is no risk of the exercise of market power in NEMA or

[41] Capacity Suppliers' Answer to Motions to Compel, filed on October 18, 2004, at 2.

any other zone. Even if suppliers' bids were not ignored, other extensive mitigation measures fully protect buyers."[42] For reasons that are discussed in more detail below, the Coalition strongly disagrees that all incentive and ability to exercise market power has been removed. Indeed, this discussion provides a perfect segue into the next section of my testimony where I demonstrate the significant market power flaws in ISO-NE's proposal that could affect any sub-regions that are designated as LICAP zones.

VI. Market Power

Q. HAS ISO-NE EFFECTIVELY ELIMINATED THE ABILITY FOR CAPACITY SUPPLIERS TO EXERCISE MARKET POWER?

A. No. Currently, the ISO-NE plan contains severe market power flaws. As usual, I'd like to lead with some numbers since they tell the story. Consider the NEMA sub-zone in this example. Under the ISO-NE plan, for the 2005 –2006 power year, NEMA will have a zonal share of OC of 5,806 MW and available capacity of 6,503 MW (LSR + CTL). Now consider a hypothetical capacity supplier that owns 2,500 MW of capacity in NEMA. If this supplier elects to deactivate a 500 MW unit for a period of 1 year, the deactivation would raise the clearing price in NEMA from about $2.40/kw-month to about $8.90/kw-month. Compare the annual revenues: 2,500 MW x $2.40/kw-month x 1,000 (conversion factor) x 12 months = $72 million, or 2,000 MW x $8.90/kw-month x 1,000 x 12 = $213.6 million. Clearly the incentive exists for this capacity supplier to do anything allowed within the rules to withhold capacity from the market, even an extended mothballing. It should be noted here that capacity suppliers would retain the right

[42] *Id.*

to mothball or retire resources through a filing under the NEPOOL tariff. The mothballing or retirement could be denied if the resource is required for reliability, but not otherwise. To date, discussions of market power abuse have focused primarily on delisting. The above example demonstrates that retirement can be a highly effective (and legal) exertion of market power as well. In deposition, ISO-NE witness Mr. LaPlante acknowledged that "[r]etirements could be used in that way, and the demand curve is transparent."[43] This example would carry over to any allowed de-listing, including de-listing for export. The bottom line is that substantial holes such as this will be unavoidable in any LICAP scheme that pays existing capacity resources unless the right to make any decisions related to retirement, deactivation and delisting is taken from resource owners. Obviously, such a change in ownership control rights would have undesirable consequences.

Q. ARE THERE MARKET POWER CONCERNS IN NEMA/BOSTON?

A. It depends on whether you are talking about market power in energy or ICAP under the proposal advanced by the ISO-NE. When markets were initially opened in NEPOOL, market power in the energy market in NEMA/Boston was a significant concern. At that time, peak demand in the area was 5,200 MW and transfer capability was 3,500 MW. When indigenous generators bid above market clearing prices outside of the NEMA/Boston area, congestion arose and out-of-merit dispatch was occasioned to the tune of $25 million per month. It was possible for suppliers to exercise market power because two suppliers controlled over 80 percent of the resources in the region. Since that time, NSTAR has been

[43] LaPlante Deposition, Vol. 2 at 462: 12-13. **]**

increasing transmission capacity into NEMA/Boston and the ISO-NE has improved its market power mitigation performance, the combination of which has resulted in very little congestion into NEMA/Boston and consequently little opportunity to exercise market power in the energy markets.

The same, however, cannot be said of the capacity markets. Concentration of resource ownership remains unacceptably high in NEMA/Boston. While NEMA/Boston does not suffer from a lack of installed capacity, the concentration of ownership of local resources results in approximately 70% of the capacity being controlled by two suppliers and 90% of the capacity controlled by three suppliers. The HHI for NEMA is 3,846. As the U.S. Department of Justice has stated "[m]arkets in which the HHI is between 1000 and 1800 points are considered to be moderately concentrated, and those in which the HHI is in excess of 1800 points are considered to be concentrated."[44] Moreover, unlike the energy markets where the constraints contributing to market power are sporadic, the local sourcing requirement under the ISO-NE's LICAP proposal enshrines market power on a perpetual basis. By designating NEMA/Boston as a LICAP zone, the ISO-NE in effect creates an artificial sub-zone within which NSTAR and other load serving entities are compelled to procure capacity from a very limited number of sellers. Even without overt collusion, the insular nature of this market makes it a prime candidate for conscious parallelism, in which a few parties follow each other's leads without the necessity of explicit agreement.

Q. WOULDN'T THE REVENUE CREDITING MECHANISM MAKE SUCH COLLUSION UNPROFITABLE?

[44] *See* http://www.usdoj.gov/atr/public/testimony/hhi.htm.

A. Not at all. The revenue crediting mechanism may discourage the exercise of market power in the energy markets but would not have any effect on conduct in the capacity market. As I have said, due to transmission upgrades and more effective mitigation, NEMA/Boston suppliers no longer have the same capacity to manipulate prices in the energy markets. There is nothing, however, to prevent suppliers from engaging in systematic and shared retirement of capacity within NEMA/Boston or exports of capacity in order to ride up the LICAP price curve to maximize revenue.

Q. HOW LIKELY IS IT THAT LOCAL SUPPLIERS COULD WITHHOLD ENOUGH CAPACITY FROM THE LICAP MARKET IN NEMA TO SIGNIFICANTLY AFFECT PRICES?

A. It is quite likely. If New Boston were to be retired, local capacity would be reduced by 350 MW. If two local suppliers were thereafter to withhold 175 MW each of capacity, either by retirement or off-system sales, local capacity would be reduced below OC. This reduction of capacity, which is allowable under ISO-NE's proposed rules, would move the clearing price to the 2 x EBCC mark, or $18.13/kw-month.

By creating a small zone, the ISO has created a very sensitive "price" curve. In a normal market, suppliers are disinclined to withhold capacity since the revenue forgone is generally greater than, or equal to, the higher revenue generated by moving supply toward the left of the price curve. In addition, even monopolists must generally guess at the elasticity of demand in order to determine how much supply to withhold in order to maximize revenue. Here, those possessing market

power know precisely how much capacity to retire or sell off-system in order to maximize revenue. When a situation is created in which an 11 percent reduction in supply would result in a 600 plus percent increase in compensation, it is highly likely that the 11 percent reduction in supply would become reality in short order.

Q. IF THEY ENGAGED IN SUCH CONDUCT, WOULDN'T THE HIGHER PRICES ENCOURAGE NEW ENTRANTS AND DEFEAT THE EXERCISE OF MARKET POWER?

A. Not necessarily. Incumbents could simply re-activate capacity anytime a potential entrant made a move to add capacity to NEMA. Moreover, "retired capacity" is not the same as dismantled capacity. Retired capacity may be brought back into the market at any time. A potential new entrant would appreciate that the incumbent could "unretire" substantial capacity at very little cost and thus obviate the attractive LICAP payment. Thus, the retirement, but not dismantling of capacity resources would become a viable business option for capacity holders to "manage" capacity revenues while preventing new entry by other parties.

Q. DID ISO-NE FULLY ADDRESS MARKET POWER CONCERNS RELATED TO DE-LISTING FOR EXPORT IN ITS OCTOBER 12, 2004 MOTION TO LODGE?

A. Unfortunately, it did not. ISO-NE took a commendable step towards reducing market power concerns by counting all available capacity in its determination of the clearing price regardless of whether or not the capacity bids into the LICAP auction. The only reason that this could be a concern for capacity suppliers is if

part of their market strategy is to move prices via their own bidding behavior. Unfortunately, the mitigation measures proposed by ISO-NE fall far short of protecting consumers from the exertion of market power through exports. Consider ISO-NE's own example in this motion: absent exports, the capacity price would have been $7 (per kw-month) in New England and $10 in New York. After counting exports, the price in New England rises to $12 while the New York price falls to $9. In the example, the two suppliers responsible for moving the market would have the price for the remainder of their capacity (that which wasn't exported) mitigated to $9.50 (Supplier A) and $10 (Supplier B) respectively. Therefore, consumers who would have paid $7 for all capacity would now pay $9.50 to Supplier A, $10 dollars to Supplier B and $12 to the remaining suppliers. The net result in this example is that, by exerting market power, Supplier A increases its capacity revenue for the month by $2.50/kw-month, or $5 million using ISO-NE's example. At the same time Supplier B increases its capacity revenue by $3/kw-month, or $3 million. All of this extra revenue would be the result AFTER ISO-NE's proposed mitigation measures are implemented. Consumers would have to pay the extra $8 million to the suppliers that were found by ISO-NE to have exerted market power and an extra $5/kw-month to all other suppliers. Let's assume for a moment that the LICAP zone in question is the Rest-of-Pool. The Rest-of-Pool has approximately 15,000 MW of capacity. After subtracting Supplier A & Bs' combined 3,500 MW, we are left with 11,500 MW x $5/kw-month x 1,000 = $57.5 million of additional LICAP costs for the month. In total, that's a $65.5 million price tag for consumers in the

rest of pool zone for one month due to the bidding behavior of two suppliers that only control a combined 23% of rest of pool capacity.

Q. DOES A CAPACITY SUPPLIER HAVE TO CONTROL A SIGNIFICANT AMOUNT OF CAPACITY TO POSESS MARKET POWER?

A. A capacity supplier does not have to be a significant player to enrich itself through the exertion of market power. In the ISO-NE export mitigation example that I discussed above, the two suppliers only held 23% of the capacity between them and were able to earn substantial gains even after ISO-NE mitigation procedures were implemented. To give another hypothetical example in the NEMA zone, consider a capacity supplier that owns only 600 MW of capacity in NEMA. Given the current state of excess capacity in NEMA for the 2005/2006 power year, the retirement of a 120 MW facility by this capacity owner would increase the clearing price from $2.40/kw-month to $4.00/kw-month. If we proceed with the same formula that I have used repeatedly in this testimony, we find that 480 MW x 4.00/kw-month = $23 million per year, while 600 MW x $2.40/kw-month = $17.3 million per year. So, in this example a supplier that only owns 600 MW of capacity could gain almost $6 million per year in capacity payments plus the reduction in operating costs attributable to the 120 MW facility by retiring or deactivating 120 MW of capacity.

Q. HOW DOES THE COALITION PROPOSAL ADDRESS MARKET POWER?

A. By targeting LICAP payments to only new resources, the Coalition LICAP proposal removes the single largest driver for market power exertion in the near

term. The Coalition fully understands that over time a higher and higher percentage of capacity will be "new" capacity subject to LICAP payments. The rules governing market power prevention will have to be refined well beyond those proposed by ISO-NE in its August 31 Filing and its October 12, 2004 Motion to Lodge.

VII. Bidding and Settlement

Q. PLEASE DESCRIBE HOW THE LICAP MARKET WOULD CLEAR UNDER THE COALITION LICAP PROPOSAL?

A. Under the Coalition LICAP proposal, there would be no bidding by capacity resources. Bidding is an attribute of a competitive market. The Coalition proposal is an administratively set incentive rate, not a market. Here are the mechanics of clearing the LICAP market being proposed by the Coalition:

1. LSRs and CTLs would be calculated for each LICAP region as per ISO-NE's August 31, 2004 proposal.

2. The Coalition price curve would be used to generate a capacity price based on the same (Zonal Resources + CTL – Zonal Share of OC) calculation used by ISO-NE. For the purpose of calculating a capacity price, all capacity will be counted since all capacity is relevant to determining the need for new capacity. As in the ISO-NE proposal, the infra-marginal rents for a reference peaking unit would be deducted from the LICAP rate for each zone. The infra-marginal rents would include both energy and non-energy related revenues.

3. A new capacity resource within a LICAP zone would earn the zonal clearing price as determined by the price curve. The allocation of payment

responsibility for LICAP incentive payments would be spread over the entire pool since the new resource would be providing a pool benefit, but such payment responsibility would be weighted to the LICAP region in which it is located with a weighting based on the clearing price differential between the zonal price and rest of pool price as a representation of relative need for the resource within and outside of the LICAP zone. The precise methodology is best described through two examples, one for NEMA and one for SWCT. For both examples assume the following:

A) Clearing prices (per kw-month) = $6.00 in NEMA and SWCT, $4.00 in Rest of CT and $2.00 in Rest-of-Pool ("ROP") and Maine

B) The new resource is 200 MW and would earn $6.00 x 200 MW x 1,000 = $1.2 million per month

NEMA Example: NEMA load would pay the incremental cost above ROP ($6 - $2) = $4 x 200 MW x 1,000 = $800,000. The remaining $400,000 is paid for by all load in NEPOOL equally (including NEMA).

SWCT Example: SWCT load would pay the incremental cost above Rest of CT ($6 - $4) = $2 x 200 MW x 1,000 = $400,000; SWCT and Rest of CT load would then pay the incremental cost of Rest of CT over ROP ($4 - $2) = $2 x 200 MW x 1,000 = $400,000; the remaining $400,000 would be paid by all load in the pool as in the NEMA example. In this manner, the relative need for the new capacity is determined by the clearing price in each zone. This is appropriate since the application of the Coalition price curve will result in differing capacity prices when certain zones evidence more of a need for new capacity resources.

4. Each LICAP zone's share of LICAP incentive costs would be allocated to wholesale load within that region.

5. The current installed capacity ("ICAP") market would remain in place, and all capacity resources would be eligible to participate. LICAP resources would be able to sell ICAP in exactly the same manner that all resources currently sell ICAP. However, each month the clearing price from the NEPOOL ICAP auction would be deducted from the each zone's LICAP rate as an infra-marginal rent.

6. The availability factor calculation proposed by ISO-NE would be applied as a reduction in LICAP revenue for any new resources that were not available during critical hours.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Devon Power LLC, *et al.*	)	**Docket No. ER03-563-030**

AFFIDAVIT OF WITNESS

I, James G. Daly, being duly sworn, depose and say that the statements contained in the foregoing testimony on behalf of the Attorney General of Massachusetts, *et al.* in this proceeding are true and correct to the best of my knowledge, information, and belief.

Executed on this 3rd day of November, 2004.

James G. Daly

Subscribed and sworn to before me this 3rd day of November, 2004.

Notary Public, State of Massachusetts

My commission expires:

NEVEN RABADJIJA
Notary Public
Commonwealth of Massachusetts
My Commission Expires
January 20, 2006

TAB 2

	(MW)	2005	2006	2007	2008	2009	2010
NEMA	(a) Local ICAP resources	3,390	3,040	3,040	3,040	3,040	3,040
	(b) Objective Capability	5,806	5,922	6,041	6,161	6,285	6,410
	ALCC	700	1,110	1,060	1,175	1,095	980
	(c) ALCC without LSWAP	650	1,060	1,010	1,125	1,045	930
	* (d):(a)-(c) LSR	2,740	1,980	2,030	1,915	1,995	2,110
	(b)-(d) CTL	3,066	3,942	4,011	4,246	4,290	4,300
CT	Local ICAP resources	6,879	7,499	7,499	7,499	7,499	7,499
	Objective Capability	7,934	8,093	8,255	8,420	8,588	8,760
	ALCC	1,020	1,400	1,410	1,380	1,230	1,080
	ALCC without LSWAP	680	1,060	1,070	1,040	890	740
	* LSR	6,199	6,439	6,429	6,459	6,609	6,759
	CTL	1,735	1,654	1,826	1,961	1,979	2,001
SWCT	Local ICAP resources	2,399	2,399	2,399	2,399	2,399	2,399
	Objective Capability	4,108	4,190	4,274	4,359	4,447	4,536
	ALCC	210	700	685	1,305	1,410	1,315
	* LSR	2,189	1,699	1,714	1,094	989	1,084
	CTL	1,919	2,491	2,560	3,265	3,458	3,452

** Load swap was not included in calculating the Local Sourcing Requirement (LSR) for consistency in comparing with ISO numbers. However, it should be noted that the Coalition's position as shown in testimony is that load swap should be included in calculating the LSR, which would properly decrease the LSR and thus increase the capacity transfer limit (CTL)*

Notes:

1. Assumes OC increases by 2% annually starting with 29,366 MW in 2005
2. Kendall CT (154 MW), Kendall ST1 (18 MW) & Kendall Jet2 (15 MW) retires in 2005 based on RTEP04
3. New Boston1 retires in parallel with 900 MW T-upgrade to NEMA in 2006 based on RTEP04
4. Phase I (550 MW) T-upgrade to SWCT & 620 MW Kleen energy in Rest of CT in service by 2006 based on RTEP04
5. Phase II (850 MW) T-upgrade to SWCT by 2008 based on RTEP04
6. 200 MW NSTAR T-upgrade to NEMA by 2008 based on NSTAR system planning
7. Load swap in NEMA = 50 MW based on ISO-NE 08/31/04 filing
8. Load swap in Rest of CT = 340 MW based on ISO-NE 08/31/04 filing
9. ALCC in each LICAP region calculated by GE
10. Local ICAP resources based on summer ratings similar to ISO 08/31/04 filing
11. ALCC refers to Additional Load Carrying Capability

TAB 3

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Devon Power LLC, *et al*.

Docket No. ER03-563-030

PREPARED ANSWERING TESTIMONY

of

Jay P. Lukens

On Behalf Of

ATTORNEY GENERAL OF MASSACHUSETTS, *ET. AL.*

NOVEMBER 4, 2004

SUMMARY OF PREPARED ANSWERING TESTIMONY

OF

DR. JAY P. LUKENS

Dr. Jay P. Lukens provides an opinion as an economist as to whether the ISO New England's proposed Locational Installed Capacity monthly capacity pricing proposal is a market mechanism that yields market-based prices. Dr. Lukens's testimony concludes that:

- The ISO New England's Locational Installed Capacity monthly capacity pricing proposal is not a "market" as it lacks an essential feature of a market, notably a process through which consumers can reveal their willingness to pay for generation capacity.

- The ISO New England's "demand curve" is not a true demand curve in the sense that that term is used by economists, but is rather an intellectual construct based on hypothetical costs of a new generation unit in New England. The ISO New England's so-called "demand curve" in no manner reflects the economic preferences of consumers, which is the hallmark of an economic demand curve. The Locational Installed Capacity monthly capacity pricing proposal is not a market but rather an administrative solution to what ISO New England perceives to be a problem - how to provide payments sufficient to incent new generation in New England.

- Inasmuch as Locational Installed Capacity monthly capacity pricing proposal prices are not "market-based," they should be scrutinized according to historic standards of utility rate making, which considers the cost of bringing forth the supply, consumer impact, and least-cost alternative solutions in discrete circumstances.

I. INTRODUCTION AND SUMMARY

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is Jay P. Lukens. I am president of Lukens Energy Group, Inc. ("LEG"), and my business address is 2905 Sackett Street, Houston, Texas, 77098.

Q: ON WHOSE BEHALF ARE YOU FILING THIS TESTIMONY?

A: I am testifying on behalf of the Attorney General of Massachusetts, Associated Industries of Massachusetts, The Attorney General of Rhode Island, The Energy Consortium, New Hampshire Office of Consumer Advocate, NSTAR Electric and Gas Corporation, The Rhode Island Division of Public Utilities and Carriers, and Strategic Energy LLC. In this testimony I refer to this group as the "Coalition."

Q: PLEASE DESCRIBE THE BUSINESS ACTIVITIES OF LEG.

A: LEG offers economic analysis, business counsel and litigation support services to buyers and sellers of natural gas, electricity and related products and services. In addition to experienced energy executives, LEG employs technical experts in the fields of finance, economics, econometrics, decision science and applied mathematics.

Q: PLEASE DESCRIBE YOUR BACKGROUND AND QUALIFICATIONS.

A: I hold B.A. and Ph.D. degrees in economics and have an extensive background in energy economics. My curriculum vitae is attached as Exhibit No. AG MASS et. al. - 4. I have provided business advice and expert testimony on a wide variety of issues involving natural gas pipelines, local gas distribution companies, energy marketing companies and electric utilities. I have also provided expert opinions in civil litigation and at the Federal Energy Regulatory Commission ("FERC") involving issues of market power and antitrust economics.

II. PURPOSE OF TESTIMONY

Q: WHAT IS THE PRIMARY PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A: I have been asked by the Coalition to provide my opinion as an economist as to whether the ISO New England's ("ISO-NE") proposed Locational Installed Capacity ("LICAP") monthly capacity pricing proposal is a market mechanism that yields market-based prices.

Q: WHAT CONCLUSIONS DO YOU REACH?

A: My conclusions are as follows:

- The ISO-NE's LICAP monthly capacity pricing proposal is not a "market" as it lacks an essential feature of a market, notably a process through which consumers can reveal their willingness to pay for generation capacity.

- The ISO-NE's "demand curve" is not a true demand curve in the sense that that term is used by economists, but is rather an intellectual construct based on hypothetical costs of a new generation unit in New England. The ISO New England's so-called "demand curve" in no manner reflects the economic preferences of consumers, which is the hallmark of an economic demand curve. The LICAP monthly capacity pricing proposal is not a market but rather an administrative solution to what ISO-New England perceives to be a problem - how to provide payments sufficient to incent new generation in New England.

- Inasmuch as LICAP prices are not "market-based," they should be scrutinized according to historic standards of utility rate making, which considers the cost

of bringing forth the supply, consumer impact, and least-cost alternative solutions in discrete circumstances.

III. THE ISO-NE'S MONTHLY CAPACITY PRICING PROPOSAL DOES NOT CREATE A MARKET AND DOES NOT YIELD MARKET-BASED PRICES

Q: WHAT DO YOU UNDERSTAND ABOUT THE HISTORY AND ORIGIN OF THIS PROCEEDING?

A: My understanding is that this proceeding grew out of a 2003 filing of certain Reliability Must Run ("RMR") contracts between the ISO-NE and certain generators located in Connecticut. These generators were viewed as necessary for reliability and the RMR agreements were envisaged to provide adequate compensation to sustain operations. In April 2003, the Commission rejected the filed RMR agreements and indicated concerns regarding the impact of the RMR agreements on the competitive market. The Commission directed that ISO-NE instead "incorporate the effect of those agreements into a market-type mechanism."[1] In response to the FERC, the ISO-NE filed a revised LICAP plan on August 31 of this year.

Q: WHAT PROBLEMS DOES LICAP PURPORT TO SOLVE?

A: The RMR issue is a subset of a potential larger problem in the New England electricity markets. Due to current surplus of installed generation capacity, the current market for energy and specifically the current value of the ISO-NE's Installed Capacity product may not adequately incent new investment in certain New England areas where new generation may be required. Further, the ISO-NE has concerns about maintaining adequate future capacity reserve margins in certain zones within the region. In describing the current market environment the ISO-NE's 2003 Annual Markets Report states that "[t]he New England system as a whole currently enjoys a surplus of generating capacity and, in a market environment, this translates into low prices for capacity. As such, capacity market revenue currently provides very little

[1] *Devon Power LLC, et al.*, 103 FERC ¶61,082 at P29 (2003)

contribution to fixed costs for generator owners and sends a signal that investment is not needed."[2] Of course, capacity market revenues are not the sole signal in the decision to build new generation, for as the Annual Markets Report states, "[t]he margin between a plant's market revenues and its variable costs (primarily for fossil fuel units) contributes to the recovery of its fixed costs, including non-variable operating and maintenance expenses and capital costs."[3]

Q: WHAT DO YOU UNDERSTAND TO BE THE CAUSE OF THIS PROBLEM?

A: Highly capital intensive, unregulated markets are prone to "boom & bust" cycles where there are periodic investment "booms" followed by periods of low product prices and declines in the values of capacity investments, followed by periods of constrained capacity and high product prices which may lead to another investment boom. The New England power market is currently suffering the after-effects of the investment boom in generation capacity in the late 1990's and early 2000's. As indicated in the ISO-NE market monitoring report, there is a surplus of generation in the New England generation market. This has lowered prices even as the ISO-NE has claimed that new investments will be needed to meet New England reliability standards and specifically for certain generating units that have provide strategic reliability value. The exit of older, less efficient units is in accordance with traditional economic theory. This is the way that markets are supposed to work. If the "boom or bust" nature of the existing market in New England is related to the inability of the market to form rational expectations about the effects of restructuring, it is not indicative of a systemic market flaw. In the immediate aftermath of restructuring in New England, the accepted wisdom was that prices would rise, and, hence, developers rushed to enter the market. So strong was the investment urge, that the queue for new construction grew to about 30,000 MW of new capacity to serve a

[2] ISO New England Inc., Annual Markets Report, page 45.
[3] ISO New England Inc., Annual Markets Report, page 58.

market with a peak demand in the 25,000 MW range. All of this occurred when the Installed Capacity market was clearing at $1.00 to $2.00 per kilowatt month. As the market develops more experience upon which to form expectations, the swings around the equilibrium should become less volatile. The problem will remain, however, how to adequately compensate the small sector of the resource market needed to satisfy capacity reserve margins and units needed to provide operating reserves without accepting high levels of reliability risk.

Q: MR. LAPLANTE SAYS THAT THE PURPOSE OF THE ISO-NE PROPOSAL IS TO PRODUCE PRICES FOR CAPACITY THAT CLOSELY REPLICATE THOSE FROM A COMPETITIVE MARKET. DO YOU AGREE THAT THEIR PROPOSAL WILL ACCOMPLISH THAT GOAL?

A: No. Nor do I agree that producing competitive prices for generating capacity is the goal of the LICAP proposal. Rather, in my opinion, the goal of the LICAP proposal is to develop prices for capacity and/or energy that provide sufficient revenues to incent generators to build and maintain generation capacity consistent with ISO-NE's reliability goals.

Q: PLEASE EXPLAIN.

A: Market analyses in New England indicate that current market revenues are not sufficient to support entry of new generation resources. Generation resources consistently on the margin in New England face incentives to exit the market. For reliability considerations, the ISO-NE wants to encourage more generation capacity in certain constrained areas and wants to do so with less uncertainty and price volatility than what might be associated with a future "boom & bust" cycle. As explained in the testimony of Coalition witness James G. Daly, the ISO-NE desires a level of generation capacity that reflects a significant reserve margin over the amount needed to serve New England's expected peak requirements. The quantity of

generation capacity desired by the ISO-NE is greater than the quantity that would result from the current capacity market design.[4] In my opinion, the fundamental issue that the Commission must address in approving a LICAP mechanism is how to bridge the cost recovery gap between the amount of capacity payments needed to maintain reliability and the payments that will result from the interaction of basic economic forces under the current ISO-NE market design. Hence I disagree with Mr. LaPlante's assertion that the goal of this proceeding is to "provide price signals consistent with those of a competitive market."[5]

Q: WHAT DO YOU UNDERSTAND ABOUT HOW THE LICAP PROPOSAL WOULD WORK IF THE COMMISISON APPROVED THE ISO-NE'S PLAN?

A: Briefly, the LICAP "market" or pricing mechanism would run on a monthly basis.[6] Load would not actively participate in the LICAP monthly pricing process, but load may hedge its obligation through bilateral contracts that the monthly LICAP pricing mechanism would recognize. Generation resources would have the option of submitting offers to sell into the LICAP "market" but have a limited option of not participating. An optimization process will be used to address transfers of capacity between ICAP regions within ISO-NE. The ISO-NE would calculate a capacity price for LICAP region's by mapping the offered quantity of capacity onto each region's so-called "demand curve". The so-called "demand curves" are not economic demand functions in any meaningful sense of that term. Rather, they are downward sloping

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[4]Market observers point to a number of contributing factors for this result, including the lack of market transparency in the retail power market, potential free rider problems, the lack of price elasticity in the supply and demand for capacity, the lack of price rationing during true scarcity conditions. See Joskow paper, pages 55-56 and generally 48 to 68. See also the discussion in the Standard Market Design Notice of Proposed Rulemaking ("SMD NOPR"), issued on July 31, 2002 in Docket No. RM01-12-000, at pages 266-276.

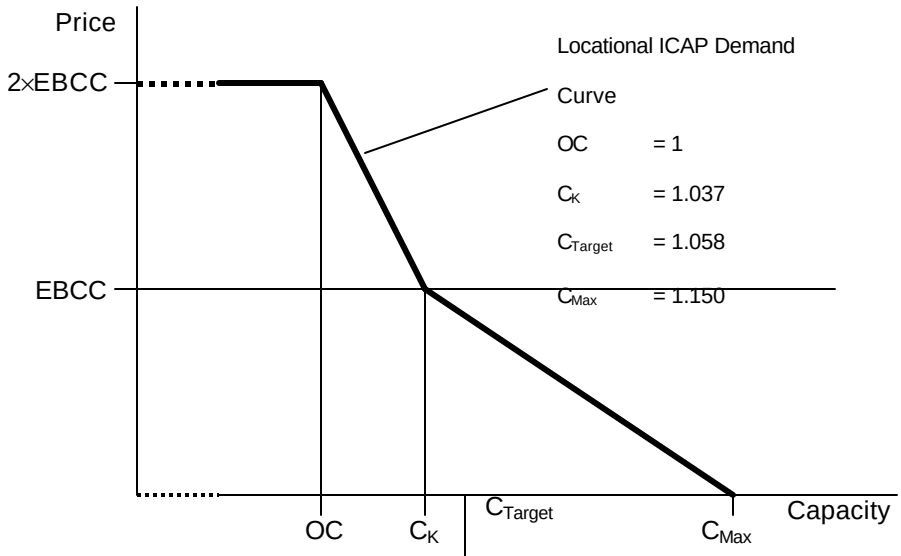
[5]Prepared Direct Testimony of David LaPlante on behalf of ISO New England Inc. ("LaPlante Testimony") page 7, at 2-3.

[6]Prepared Direct Testimony of Mark Karl on behalf of ISO New England Inc. ("Karl Testimony"), page 6 at 1.

functions (DSFs) defined in a space that has multiples of an Estimated Benchmark Cost of Capacity ("EBCC") on the vertical axis and multiples of the ISO-NE's Objective Capability ("OC") on the horizontal axis. A separate DSF will be defined for each Locational ICAP Region based on its share of the OC. The LICAP "market" will clear all LICAP regions at the same time using a regional ratio of installed capacity to OC ("IC/OC") and each region's DSF.

The ISO's LICAP monthly pricing mechanism is a combination cost of service and replacement cost ratemaking approach that uses the EBCC to "position" the DSFs described by the ISO-NE witnesses as a "demand curves." Sellers of capacity are paid a multiple of the EBCC depending on the ratio of IC/OC. The multiple is 2.0 if the offered quantity of installed capacity is less than or equal to the OC.[7] It is between 1.0 and 2.0 if the offered quantity of installed capacity is between the region's OC and 103.7% of the OC. The multiplier of EBCC declines to zero as the offered quantity of installed capacity increases to 115% of the region's OC.

[7]For 2005 the projected OC is 29,366 vs. a projected peak load requirement of 26,310 MW. Thus the definition of the OC already incorporates 3056 MW of capacity over the projected peak.



Source: Stoft Testimony, page 16.

Q: WHAT IS THE BASIS FOR YOUR CONCLUSION THAT THE MONTHLY LICAP MECHANISM IS NOT A MARKET?

A: The most fundamental tenet of market economics is choice. The monthly LICAP pricing mechanism is not a market and it does not yield market-based prices because it provides sellers of generation resources limited choices about how much capacity they are willing to sell at a given price, and eliminates the ability of the buyers to choose how much they are willing to buy at a given price. The ISO-NE LICAP monthly pricing mechanism substitutes the judgment of the ISO-NE for the ability of buyers to choose. In my view it is more accurately described as a "look-up table" proposal – given the amount of capacity offered the ISO-NE will "look-up" the resulting price from its hypothetical cost-based DSF and return a price. ISO-NE witness Mark Karl states that "[l]oad-serving market participants do not directly

participate in the auction, but are represented in aggregate by the demand curve in each Locational ICAP Region."[8]

Q: ARE THERE OTHER FACTORS FORMING THE BASIS OF YOUR CONCLUSION THAT THE MONTHLY LICAP PRICING MECHANISM IS NOT A TRUE MARKET?

A: Yes. Energy markets, or markets for any other commodity or good for that matter, require the interaction of buyers and sellers in arms-length transactions in a commercial setting. Through such interaction buyers and sellers exchange information and create price signals, which in turn assist society to determine what is produced, how it is produced, and how products are distributed. By eliminating any mechanism through which consumer preferences and information can be reflected in the LICAP price it is predictable that such prices will always be "wrong" in the sense of being economically inefficient. Any administrative price setting scheme that does not use actual consumer and supplier information is divorced from the economic decisions of consumers and cannot be considered a market, and the resulting prices cannot be considered "market-based." The Commission, in its Standard Market Design NOPR, stated that "[a] well-designed resource adequacy requirement supports competitive markets if it allows suppliers to compete to provide infrastructure and buyers to choose the infrastructure with the best combination of features such as cost, reliability, environmental effects, and service life."[9] In this case the ISO-NE has simply taken "buyer choice" out of the monthly LICAP pricing mechanism by substituting a hypothetical "demand curve" for consumer preferences. The proposal ignores preferences about the "best combination of features" and instead incorporates only information on the difference between the amount of capacity that the ISO has determined is required and the installed capacity in a geographical market area.

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[8]Karl Testimony, page 7 at 21-23.
[9]SMD NOPR, page 272.

Q: DOES THE ISO-NE DESCRIBE ITS LICAP MONTHLY PRICING MECHANISM AS MARKET BASED?

A: Yes. The term "LICAP market" appears frequently in the testimony of the ISO witness. In my opinion this is clearly an incorrect use of the economic term "market."

Q: WHAT FACETS OF THE ISO-NE'S SO-CALLED DEMAND CURVE RESEMBLE THE ECONOMIC CONCEPT OF A DEMAND CURVE?

A: The only resemblance of the ISO-NE's DSF to a real demand curve is that the ISO-NE's so-called demand curve produces higher quantity demanded at lower prices, and conversely, lower quantity demanded at higher prices, i.e., it is a downward sloping function in a certain price/quantity space. At that point, the similarities between the ISO-NE's so-called demand curve and a real demand curve stop. There is no mechanism for consumers to express their preferences in the ISO-NE's price setting scheme. Instead of actual consumer bids in the ISO-NE's demand curve, there is an administratively determined price based on the amount of installed capacity in a LICAP region and the cost of a new New England generation unit.

The so-called "demand curve" is described by its principal creator, Dr. Stoft, as the "cost approach."[10] Mr. LaPlante's description of the so-called "demand curve" reveals profound confusion regarding fundamental economic concepts of demand, supply and market equilibrium: "The sloped demand curve was intended to implement an essential feature of any operating market, that is, prices increase as supply declines …".[11] In economics, of course, the demand curve is intended to reflect consumer willingness to pay at various product prices. Due to scarcity,

[10]Prepared Direct Testimony of Steven E. Stoft on behalf of ISO New England Inc., ("Stoft Testimony"), page 10 at 8-13.
[11]LaPlante Testimony, page 7 at 3-5.

consumers are generally willing to consume less at higher prices, hence demand curves have a downward slope. Supply curves are a separate construct altogether revealing the willingness of producers to supply their product at various market prices; and price determination results from interaction of supply and demand. Mr. LaPlante's description of the so-called "demand curve" is muddled because the DSF is not in fact a properly defined demand curve.

Q: DR. STOFT CONSIDERS, THEN REJECTS AN APPROACH BASED ON CONSUMER VALUE OF LOST LOAD.[12] DO YOU DISAGREE WITH HIS OPINION THAT THIS CONCEPT IS DIFFICULT TO IMPLEMENT EMPIRICALLY?

A: No, but potential difficulties in estimating the value of lost load is not a justification for ignoring the value that consumers place on capacity. At a minimum, consumer values of capacity ought to be considered, despite practical difficulties in estimation, if for no other reason than to provide a point of comparison to the ISO-NE's cost-based approach. As proposed, it is my opinion that the ISO-NE's LICAP monthly auction proposal is simply a novel approach to cost-of-service pricing. As such, I recommend that the proposal should be scrutinized according to historic standards of utility rate making, which considers the cost of bringing forth the supply, consumer impact, and least-cost alternative solutions in discrete circumstances.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes it does.

[12] Stoft Testimony, pages 5-6.

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Devon Power LLC, *et al.*

Docket No. ER03-563-030

AFFIDAVIT OF WITNESS

I, Jay P. Lukens, being duly sworn, depose and say that the statements contained in the foregoing testimony on behalf of the Attorney General of Massachusetts, *et al.*, in this proceeding are true and correct to the best of my knowledge, information, and belief.

Executed on this 3 day of November, 2004.

Jay P. Lukens

Subscribed and sworn to before me this 3 day of November, 2004.

Notary Public

DONNA G. CAMPBELL
Notary Public, State of Texas
My Commission Expires
November 22, 2006

State of Texas, County of Fort Bend

TAB 4

JAY P. LUKENS

Lukens Energy Group, Inc.
2905 Sackett Street, Suite 200
Houston, Texas 77098
(713) 961-1100

PROFESSIONAL EXPERIENCE

Lukens Energy Group, Inc., Houston, TX
President, January 1999 – present

Founder of energy consulting and software products firm offering economic analysis, business counsel, litigation support services and analytical software products to buyers and sellers of natural gas, electricity and related products and services. Areas of expertise include economics of deregulation, market power analysis, and energy asset evaluation and optimization. Provides expert testimony in conjunction with civil litigation and regulatory proceedings.

The Economics Resource Group, Inc., Houston, TX
Managing Director, August 1996 – December 1998

Principal of the firm and head of the Houston office. Lead consultant on variety of assignments regarding business and regulatory strategy for electric utilities, natural gas pipelines and distributors, and energy marketing firms.

Energy Market Economics, Inc., Houston, TX
President, November 1995 - August 1996

Founder of consulting firm offering services to energy firms in the areas of business strategy, project evaluation and development, expert witness, and regulatory support.

Transcontinental Gas Pipe Line Corporation, Houston, TX
Senior Vice President, 1989 - 1995

Principal commercial officer with accountability for operating income performance and direct responsibility for business strategy, rates, and federal regulatory affairs. Served as company's principal negotiator in rate cases, transition cost recovery proceedings, and settlements of major civil lawsuits. Directed Transco's implementation of FERC *Order No. 636*. Represented Transco as a policy witness in FERC proceedings. Had P&L responsibility for Transco's gas marketing business during 1991-92. Initiated and directed two major projects to align internal business processes with new competitive environment.

Vice President, Market Development and Planning, 1986 - 1989

Directed Transco's rates, planning, and business development activities. Served as Transco's principal negotiator in FERC's Northeast Open Season proceeding. Developed, marketed, and obtained regulatory approval for projects to expand Transco's capacity by over 10 percent (over 500 MMCFD) with associated capital investment of almost $300 million. Negotiated contracts with other pipelines to market gas storage and Canadian gas supply projects on Transco's system. Managed Transco's interests in several joint ventures with other interstate pipelines. Evaluated proposals for Transco to acquire or divest pipeline properties and gas production assets.

Director, Strategic Planning, 1985 - 1986

Developed annual budgets, long-range plans, and special studies to support business development activities. Developed market analysis of Transco system that guided market development efforts over the next five years.

AT&T Communications, Basking Ridge, NJ
Staff Manager, 1981 - 1985

Worked in an internal consulting group known as the Analytical Support Center. Led interdisciplinary teams in analyses of a wide range of strategic and operational issues. Principal work related to the impacts of deregulation and divestiture on AT&T's service structure and pricing strategy. Developed competitor analysis methods and systems. Managed market research and economic modeling to evaluate new network services.

Resources Research Corporation, Bryan, TX
Economist, 1978 - 1981

Analyzed data and provided general research support for consulting projects. Principally responsible for econometric studies of markets for medical and dental services.

EDUCATION

Texas A&M University, College Station, TX
Ph.D., Economics, 1981

Eckerd College, St. Petersburg, FL
B.A., Economics, 1977

TESTIMONY

SCANA Corporation

Testimony on behalf of SCPC in response to a Public Service Commission of South Carolina. Expert Testimony in response to an order directing SCPC to present testimony and information in a proceeding concerning put options and other financial devices that maybe employed by SCPC in its purchase of gas supplies to meet the future demand of its customers. Docket No. 2003-236-G. Written report filed October 30, 2003.

Grynberg

Shell Oil Company, Shell Western E&P Inc., Shell Cortez Pipeline Company, Kinder Morgan CO2 Company, L.P., formerly known as Shell CO2 Company, Ltd. ("Shell"), Exxon Mobil Oil Corporation, formerly known as Mobil Oil Corporation, Mobil Producing Texas and New Mexico, Inc., ("Mobil"), and Cortez Pipeline Company. Expert Testimony that analyzed the Plaintiffs' claims concerning the tariffs charged by Cortez Pipeline Company to move CO2 from the McElmo Dome Unit in southwestern Colorado to Denver City, Texas in the Permian Basin. Docket No. 1998 CV-43. Written report filed June 20, 2003.

Reliant Energy Power Generation, Inc. and Reliant Energy Services, Inc.

San Diego Gas and Electric Company, Complainant v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Power Exchange. Affidavit responding to FERC Staff's Final Report on Price Manipulation in Western Markets. Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices. Docket No. PA02-2-000. Written report filed April 25, 2003.

Northern Indiana Public Service Company

Rebuttal Testimony before the Indiana Utility Regulatory Commission. Expert Testimony in NIPSCO's 2003 Gas Cost Adjustment Case that addresses issues raised in the Indiana Office of Utility Consumer's Counselor's (OUCC) regarding the run up of gas prices in March 2003. Written report filed April 9, 2003.

Piedmont Natural Gas Company

Report on Analysis of Market Power Related to the Proposed Purchase of North Carolina Natural Gas. Expert Testimony examining whether the acquisition of North Carolina Natural Gas will lead to an increase in market power that could be detrimental to the welfare of consumers. Written report filed December 6, 2002.

Reliant Energy Power Generation, Inc. and Reliant Energy Services, Inc.

Report on California Border Prices - Fact Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices. Expert Testimony analyzing the Initial Report of FERC Staff in Docket No. PA02-2-000 (August 2000) Written report filed October, 2002.

Nova Scotia Power Inc. (NS Power)

Report on Agency and Surplus Thermal Generated Energy Purchase and Sale Agreement between Emera Energy Inc. and Nova Scotia. Expert Testimony analyzing the economic and regulatory policy implications of the Agency and Surplus Thermal Generated Energy Purchase and Sale Agreement between Nova Scotia Power Inc. and Emera Energy Inc. Written report filed October 4, 2002.

EnerGas (The City of Lubbock)

The City of Lubbock, Texas and the West Texas Municipal Power Agency vs. Stewart & Stevenson Energy Products, Inc., aka S&S Energy Products, Inc., a Division of GE Packaged Power, Inc., and EnerGas, a Division of ATMOS Energy; Cause No. 2001-513, 945; in the 99th Judicial District Court of Lubbock County, Texas. Expert Testimony evaluating the assumptions made in Plaintiffs'damage calculation, and analyzing the economic logic employed in calculating purported economic damages. Written report filed August 22, 2002.

ProGas Limited (ProGas)

In the Matter of a Gas Purchase Contract by and between ProGas Limited as Seller, and Ocean State Power, as Buyer Dated December 14, 1998, as Amended Effective December 1, 1999. Prepared direct testimony in a private arbitration dispute regarding analysis of the arbitration standard in a gas sales contract. Written evidence filed August 17, 2002. Response Testimony filed October 17, 2002.

Transcontinental Gas Pipeline Corporation (Transco)

United States of America before the Federal Energy Regulatory Commission, Docket No. RP01-245-000, et al. Prepared Rebuttal Testimony addressing the economic substance of, and the regulatory issues concerning a transaction between Transco and Williams Communications Company ("WCC"), wherein Transco agreed not to oppose WCC's use of the Transco right-of-way. Written Report filed May 31, 2002.

Amoco Production Company

Richard Parry, et al., vs. Amoco Production Company; *Case No. 94 CV 105; District Court, County of La Plata, State of Colorad*o. Expert testimony analyzing the economic implications of the Plaintiffs' and Experts' claims regarding post-production fees charged by Amoco for Coal Seam Gas in the San Juan Basin. Written Report filed May 1, 2002.

Amoco/Shell/Amerada Hess

Ray Powell, Commissioner of Public Lands of the State of New Mexico, Trustee, vs. Amoco Production Company, Amerada Hess Corporation, Shell Western E&P, Inc., and Shell Land & Energy Co.; *Case No. D-0101-CV-2000 02079; First Judicial District, State of New Mexico, County of Santa Fe*. Expert testimony analyzing the economic implications of the Plaintiff's and its Experts' claims concerning the tariffs charged for transportation of CO_2 on the pipelines connecting the Bravo Dome to EOR projects in the Permian Basin. Written Report filed September 21, 2001. Supplemental Expert Report filed January 11, 2002.

Exxon Mobil Corporation

DETMI Management, Inc., Duke Energy Services Canada Ltd., and DTMSI Management, Ltd. vs. Mobil Natural Gas, Inc. and Mobil Canada Products, Ltd.; Cause No. 50 T 198 00485 00; American Arbitration Association. Expert testimony analyzing the natural gas and power trading and marketing business in connection with a dispute regarding the operation of Duke Energy Trading and Marketing, a joint venture of Duke Energy and Exxon Mobil. Written Expert Report filed July 31, 2001.

Shell Oil Company, Shell Western E&P, Inc., and Mobil Producing Texas and New Mexico, Inc.

CO2 Claims Coalition, et al., vs. Shell Oil Company, et al., in the United States District Court for the District of Colorado, CIV. No. 96-Z-2451. Expert Report analyzing the economic implications of the Plaintiffs' and their Experts' claims concerning price fixing and anti-competitive behavior in establishing the tariffs charged by Cortez Pipeline Company to move CO_2 from the McElmo Dome Unit in southwestern Colorado to Denver City in the Permian Basin. Second Supplemental Expert Report filed March 30, 2001.

Philadelphia Gas Works

Before the Pennsylvania Public Utility Commission, Philadelphia Gas Works Docket No. R-00006042 Prepared Direct Testimony in Philadelphia Gas Works' Base Rate Proceeding addressing the cost of service of the company if it were an investor owned utility. January 16, 2001.

Carthage Energy Services, Inc. and Dominion Energy

United States of America before the Bankruptcy Court for the Southern District of Texas, Houston Division, Case No. 99-32383-H2-11, Case No. 99-32384-H4-11, Jointly Administered under Case No. 99-32383-H2-11, Adversary No. 00-3290. Expert Report related to certain damage calculations under the Proof of Claim filed by Carthage Energy Services on May 4, 2000. Also reviewed the reports submitted by the Trustee's Experts and responded to certain statements contained in such reports, January 6, 2001.

El Paso Natural Gas Company

United States of America before the Federal Energy Regulatory Commission, Public Utilities Commission of the State of California v. El Paso Natural Gas Company, et al., Docket No. RP00-241-000. Expert Report analyzing the performance of the California gas market, filed in rebuttal to claims by the CPUC that El Paso had exercised market power over natural gas transportation services serving California, September 29, 2000. Report updated December 13, 2000.

Texas Gas Transmission Corporation

United States of America before the Federal Energy Regulatory Commission, Texas Gas Transmission Corporation, Docket No. RP00-260-000. Testimony supporting proposal for seasonal and term differentiated rates for short-term transportation services. Also addressed analysis of the supply and demand balance and the business risk in the market for pipeline capacity in which Texas Gas participates, April 21, 2000.

ATCO Gas Company

Before the Alberta Energy and Utilities Board, Nova Gas Transmission Ltd., on behalf of ATCO Gas Company. Testimony for alternative rate design for Nova Gas Transmission Ltd. Written evidence submitted on August 10, 1999.

El Paso Natural Gas Company

United States of America before the Federal Energy Regulatory Commission, El Paso Natural Gas Company, Docket No. RP97-287-010. Expert Report filed to rebut claims by CPUC regarding effect on California gas market of contract between Dynegy Corp. and El Paso Natural Gas, May 6, 1999.

El Paso Natural Gas Company

United States of America before the Federal Energy Regulatory Commission, Docket No. RM98-10, Regulation of Short-Term Natural Gas Transportation Services, Docket No. RM98-12, Regulation of Interstate Natural Gas Transportation Services. Expert Report (with Adam Jaffe) regarding economic impact of FERC's proposed rule, April 12th, 1999.

Transcontinental Gas Pipeline Company

United States of America before the Federal Energy Regulatory Commission, Transcontinental Gas Pipeline Company, Docket No. CP98-74-001. Prepared Answering Testimony on behalf of Transco analyzing competitive effects of refusal to construct interconnect, January 5, 1999.

Northern Natural Gas Company and Dynegy Energy Resources, Limited Partnership,

Bearpaw Gathering Systems, Inc., et al., vs. Northern Natural Gas Company and Dynegy Energy Resources, Limited Partnership, f/k/a NGC Energy Resources, Limited Partnership, vs. Ocean Energy, Inc., in the United States District Court for the Southern District of Texas, Cause No. 97-47540. Expert testimony in natural gas contract dispute, December 22, 1998.

Shell Oil Company, Shell Western E&P, Inc., and Mobil Producing Texas and New Mexico, Inc.

CO2 Claims Coalition, et al., vs. Shell Oil Company, et al., in the United States District Court for the District of Colorado, CIV. No. 96-Z-2451. Expert Report analyzing the economic implications of the Plaintiffs' and their Experts' claims concerning price fixing and anti-competitive behavior in establishing the tariffs charged by Cortez Pipeline Company to move CO_2 from the McElmo Dome Unit in southwestern Colorado to Denver City in the Permian Basin, November 2, 1998. Supplemental Expert Report filed April 30, 1999.

El Paso Natural Gas Company

United States of America before the Federal Energy Regulatory Commission, El Paso Natural Gas Company, Docket No. RP97-287-010. Expert Report (with Adam Jaffe) filed with the Initial Comments of El Paso in the technical conference in this docket analyzing the policy issues raised by the contracts between El Paso and Natural Gas Clearinghouse, February 26, 1998. Expert Report filed with the Reply Comments of El Paso in the technical conference in this docket analyzing the competitive impacts of the contracts between El Paso and Natural Gas Clearinghouse, April 14, 1998.

Texas New Mexico Power Company

State of Texas, State Office of Administrative Hearings, Application for Approval of the TNMP Transition Plan and Statement of Intent to Decrease Rates, and Municipal Rate Appeals, SOAH Docket No. 473-97-1561. Prepared Rebuttal Testimony in Support of Restated Stipulation. Policy testimony on terms of competition and conditions of entry in electric restructuring case, March 2, 1998.

AEC Oil & Gas, a Division of Alberta Energy Company, Ltd., Canadian Forest Oil Ltd., and ProGas Limited

In Arbitration, Alberta Northeast Gas Limited vs. AEC Oil & Gas, a Division of Alberta Energy Company, Ltd., Canadian Forest Oil Ltd., and ProGas Limited. Testimony regarding proper interpretation of long-term gas sales contract. Prepared Direct Testimony, January 26, 1998. Reply Testimony, February 11, 1998.

CNG Transmission Corporation

United States of America before the Federal Energy Regulatory Commission, CNG Transmission Corporation, Docket No. RP97-406-000. Prepared Direct Testimony. Expert testimony on market power in secondary market for pipeline capacity, July 1, 1997.

Leidy Line Roll-in Group

United States of America before the Federal Energy Regulatory Commission, Transcontinental Gas Pipe Line, Docket No. RP95-197 & RP 97-71 (Consolidated). Prepared Answering Testimony, March 25, 1997. Cross-Answering Testimony filed May 12, 1997.

Amoco Production Company

In the Matter of Doris Feerer, et al. vs. Amoco Production Company, et al., Civ. No. 95-0012-JC/WWD in United States District Court for the District of New Mexico. Expert report regarding vertical integration and transfer pricing in a royalty dispute, May 5, 1997.

Oklahoma Gas and Electric Co.

Prepared Rebuttal Testimony before the Corporation Commission of the State of Oklahoma, Cause No. PUD 960000116, on behalf of Oklahoma Gas and Electric Company. Recommended the proper allocation of costs for the Enogex pipeline system between Oklahoma Gas and Electric and third party transportation services, November 6, 1996.

Nashville Gas Company

Prepared Direct Testimony before the Tennessee Public Service Commission, Docket No. 96-00805, on behalf of Nashville Gas Company, A Division of Piedmont Natural Gas Company. Proposed a performance incentive program for Nashville's gas procurement and capacity costs, April 22, 1996.

Leidy Line Roll-in Group

United States of America before the Federal Energy Regulatory Commission, Docket No. RP95-197-000 (Phase II). Expert testimony supporting rolled-in rate treatment for Transco's existing incrementally priced expansion projects. Other Answering and Rebuttal Testimony filed as case progressed, January 24, 1996.

Transcontinental Gas Pipe Line Corporation (Transco)

United States of America before the Federal Energy Regulatory Commission, Docket No. RP95-197-000, Prepared Direct Testimony on behalf of Transco. General policy issues in rate case, March 15, 1995.

United States of America before the Federal Energy Regulatory Commission, Docket No. RP93-100, Prepared Direct Testimony on behalf of Transco, supporting the terms and conditions of Transco's contract settlement with Dakota Gasification. Other Supplemental, Answering, and Rebuttal Testimony filed as case progressed, December 19, 1994.

United States of America before the Federal Energy Regulatory Commission, Docket No. RM94-4, Public Conference on Natural Gas Gathering Issues, testimony and response to questions before the Commission members and their staff, February 24, 1994.

United States of America before the Federal Energy Regulatory Commission, Docket No. RP92-137, Prepared Direct Testimony on Behalf of Transco, addressing general policy issues in rate case; primary issue in litigated phase of the case was the design of rates for production area services. Supplemental, Answering, and Rebuttal testimony filed as case progressed, March 17, 1992.

United States of America before the Federal Energy Regulatory Commission, Docket No. RP92-108, Prepared Direct Testimony on Behalf of Transco, supporting general policy issues in rate case, March 10, 1992.

United States of America before the Federal Energy Regulatory Commission, Docket No. CP92-378, Prepared Direct Testimony on Behalf of Transco, addressing the design of an incentive rate mechanism for gas pipelines, February 28, 1992.

United States of America before the Federal Energy Regulatory Commission, Docket No. RM90-1, Public Conference on Pipeline Construction Rulemaking, testimony and response to questions before the Commission members and their staff, January 28, 1992.

United States of America before the Federal Energy Regulatory Commission, Docket No. RP90-8, Prepared Direct Testimony on Behalf of Transco, supporting proposal for new transportation rate design consistent with unbundled service structure, October 24, 1989.

United States of America before the Federal Energy Regulatory Commission, Docket No. RP87-7, Prepared Direct Testimony on Behalf of Transco, addressing the reserved issues of rate design and the terms and conditions of transportation service; supported proposal for a price deregulated secondary market in pipeline capacity rights, June 21, 1989.

United States of America before the Federal Energy Regulatory Commission, Docket No. TA85-3-29, Prepared Answering Testimony on Behalf of Transco in remedies phase of FERC enforcement action, February 13, 1989.

PUBLICATIONS AND RESEARCH

"Getting Real: How to Optimize the Value of Storage Assets" with Deepa Poduval, *Natural Gas*, October 2002.

"Increasing Price Volatility Sparks Interest in Energy Finance Arena", *Houston Business Journal,* June 1-7, 2001.

"Pricing and Integrated Energy Transmission Grid: Are FERC's Natural Gas and Electric Power Transmission Pricing Policies on a collision course?" *The Electricity Journal,* March 2000.

"The Pipeline's View: FERC's Proposed Rule Misses the Mark," with Adam Jaffe, *Public Utilities Fortnightly,* July 1, 1999.

"Benefits of Retail Electricity Competition in Low Cost States," with Greg Hopper and Frank Felder, *Electricity Journal,* August/September 1998.

"Should a Marketer Manage Your Supply Assets?" with Greg Hopper, *Hart's Energy Markets,* February 1998.

"Whither the Contract for Pipeline Capacity," *Natural Gas Focus,* January 1996.

"Comparison of Transportation Information Systems in the Gas and Electric Industries," EME Working Paper, December 1995.

SELECTED RECENT PRESENTATIONS

"Emerging Strategic Issues for LDCs," presentation to Southern Gas Association Board of Directors, April 2003

"Gas – Power Convergence," presentation to PSEG's senior management group, April 2003

"Valuation of Energy Companies" two-day seminar conducted in London for *Euromoney* Training

"Valuation of Gas Storage and Transportation Assets," INFOCAST Seminar, October 2002

OTHER PROFESSIONAL ACTIVITIES

Member, Energy Bar Association, 2001 - 2003

E-Commerce Committee Chair, Energy Bar Association, 2002 - 2003

International Association for Energy Economics, 1996 - 2003

Board of Directors, INGAA Foundation, 1989 - 1995, 1997 - 2002

Member, Rate Committee, INGAA, 1986 - 1995

Member, Policy Analysis Committee, INGAA, 1986 - 1995

HONORS AND AWARDS

Recipient of the Alfred Chalk Award to the Outstanding Graduate Student, Department of Economics, Texas A&M University, 1981

Thomas Presidential Scholar, Eckerd College, 1973 – 1977

TAB 5

Exhibit No. AG Mass.*, et al.* -5

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PREPARED DIRECT TESTIMONY OF

CHARLES P. SALAMONE

ON BEHALF OF

THE ATTORNEY GENERAL OF MASSACHUSETTS*, ET AL*.

DOCKET NO. ER03-563-030

NOVEMBER 4, 2004

SUMMARY OF DIRECT TESTIMONY OF
CHARLES P. SALAMONE

Mr. Charles Salamone, Director of System Planning for the electric subsidiaries of NSTAR Electric and Gas Corporation ("NSTAR") discusses the coordinated planning process among ISO New England Inc. ("ISO-NE") and transmission companies in New England, including NSTAR, with respect to upgrades and expansion of the transmission system in this region. These coordinated efforts lead to the development of the Regional Transmission Expansion Plan ("RTEP") produced by ISO-NE each year, the most recent version having been designated as RTEP04.

RTEP04 includes NSTAR's 345 kV Reliability Transmission Project (the "Project"), as described in Mr. Salamone's testimony. Mr. Salamone discusses the benefits of this Project, including an anticipated increase in import capability for the NEMA/Boston area, which will serve to alleviate a majority of the concerns for maintaining the reliability of the transmission system serving the area. Mr. Salamone testifies as to the status of the Project - it is progressing in a manner consistent with the original schedule for its construction and 2006 in-service date. The NSTAR organization is highly focused on keeping the Project on schedule and is confident that the Project will be in-service when it is projected to be.

The Project, together with other upgrades made to the transmission system in the NEMA/Boston area, serve to minimize any transmission congestion issues for the NEMA/Boston area. Increased import capability leads to greater availability for the area to access external resources, while reducing any dependency on local area generation. Units in the NEMA/Boston area will become primarily responsible for meeting region-

wide demand when dispatched economically and providing local operating reserves – a role no different from that of any generator on the system serving New England as a whole. In light of these considerations, Mr. Salamone concludes that from a reliability perspective, there is no reason for NEMA/Boston to be designated as a separate LICAP zone.

Additionally, Mr. Salamone discusses the NEMA/Boston "load swap" issue. The NEMA Load Swap is a real NEMA resource that can be relied upon during the "Critical Hours" in ISO-NE's proposal. Mr. Salamone concludes that ISO-NE erred by not considering the NEMA Load Swap in its local area supply requirements calculations for NEMA.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Devon Power LLC, *et al*.	**)**	**Docket No. ER03-563-030**

DIRECT TESTIMONY OF CHARLES P. SALAMONE

Q. Please state your name and business address.

A. My name is Charles P. Salamone. I am Director of System Planning for the electric subsidiaries of the NSTAR Electric and Gas Corporation (the "Company"), with an address of One NSTAR Way, Westwood, Massachusetts.

Q. Please describe your education and professional background.

A. I hold a Bachelor of Science Degree in Electrical Engineering from Gannon University. I joined the Engineering Department of Commonwealth Electric Company in July of 1973. At that time, I became a Junior Planning Engineer where my primary responsibilities were to assist in the planning, analysis and design of the transmission and distribution systems of the company. I generally followed the normal progression of positions with increasing levels of responsibility within the planning area until taking my current position in 2000. I have previously served as Chair of the NEPOOL Planning Policy Subcommittee (1997-1998), Chair of the NEPOOL Regional Transmission Planning Committee (1998-1999) and Vice Chair of the NEPOOL Reliability Committee (1999-2000). I am a Registered Professional Engineer with the Commonwealth of Massachusetts. I am also a member of the Power Engineering Society of the

Institute of Electrical and Electronic Engineers. A copy of my resume is attached hereto as Exhibit No. AG Mass., *et al*-6.

Q. Have you previously testified before the Federal Energy Regulatory Commission or other regulatory agencies?

A. Yes. I have previously testified before the Federal Energy Regulatory Commission, the Massachusetts Department of Telecommunications and Energy and the Massachusetts Energy Facilities Siting Board on a number of technical matters relating to system planning.

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

A. The purpose of my testimony is to discuss the implications of the transmission upgrade schedule in the Regional Transmission Expansion Plan (RTEP) produced by ISO-NE. The most recent version of this plan, designated RTEP04, was approved by the ISO-NE Board of Directors on October 21, 2004. It serves as the most current example of the coordinated planning process employed in New England and includes the Company's 345 kV Reliability Transmission Project, which is scheduled to be on-line in mid-2006 ("2006 345 kV Project"), as well as other transmission upgrade projects for the Company's service area. In particular, my testimony will describe the benefits of the 2006 345 kV Project, and confirm that the Company is proceeding with the project and that it is expected to be in service in 2006 as scheduled. My testimony will also explain how the planning process employed at the Company in conjunction with ISO-NE has served to minimize any transmission congestion issues for the NEMA/Boston area

supporting a conclusion that the NEMA/Boston should not be designated as a LICAP zone.

Q. Please describe the benefits of the 2006 345 kV Project including the expected increase in import capability for the NEMA/Boston area.

A. The 2006 345kV Project consists of an 18 mile, 3 circuit, 345 kV underground transmission line that will connect a new 345 kV substation in the southern part of the service territory with two existing 345 kV to 115 kV stations located at the center of the Boston service territory. This project will be a major undertaking by the Company and it will serve to mitigate a majority of the concerns for maintaining the reliability of the transmission system serving the area. The project, while primarily focused on resolving local area transmission reliability concerns, also provides for a significant increase in the transmission import capability for the region. Studies have indicated that at least a 1000 MW improvement in the Boston Import area Normal Transfer[1] import capability and a 1400 MW improvement in the Emergency Transfer[2] import capability can be expected as a benefit beyond the identified transmission reliability enhancements. These increases in import capability significantly reduce any dependency on local area generation and make available a significant amount of resources external to the area. The result is that transmission congestion for the area is substantially eliminated since generating units in the area would only need to be dispatched under heavy load conditions when the majority of these units are in merit and

[1] Normal Transfer is defined in NEPOOL Planning Procedure PP-3 Reliability Standards for the New England Power Pool.
[2] Emergency Transfer is defined in NEPOOL Planning Procedure PP-3 Reliability Standards for the New England Power Pool.

dispatched on an economic basis. Additionally, as the full capacity of these new lines cannot be completely utilized due to constraints elsewhere in the area there is potential for even greater improvements in import capability if other limiting elements are upgraded or other new transmission facilities are added to the system. Investigations concerning the potential increase in import capability beyond the 1000 MW improvement have shown that other upgrades, such as the addition of the proposed new National Grid 345 kV Scobie to Tewksbury transmission line, could potentially raise the import level by another 500 MW to 1000 MW. Additional studies are needed to identify the set of transmission system upgrades and additions needed to fully utilize the capabilities of the 345 kV Project in terms of increasing the import capability beyond the stated 1000 MW improvement. These studies are part of the RTEP process and are scheduled to begin early next year and will ultimately serve to identify the specific transmission system upgrades that would allow for greater import capabilities to the area.

Q. What is the status of the 2006 345 kV Project? Does the Company anticipate that it will be in-service on schedule?

A. The 2006 345 kV Project is progressing in a manner consistent with the original schedule for its construction and in-service date. Regulatory proceedings, NEPOOL review, ISO-NE review, and Transmission Expansion Advisory Committee reviews have all been completed with only a limited set of issues remaining to be resolved relative to the construction details of the project. The Massachusetts Energy Facilities Siting Board review and approval process is one

that is a comprehensive evaluation of the proposed plans requiring at least a one year review requiring public hearing, extensive documentation and evidentiary hearings. This review is very close to completion with all documentation and hearings completed and only issuance of a final order pending for approval of the project. Some equipment such as the 800,000 feet of steel pipe needed for the project has already been ordered and additional equipment will be ordered over the next 10 months as needed to keep the project on schedule. The project was divided into two phases to allow for completion of the more critical elements when they are needed. The first phase of the project includes installation of a 345 kV Switching Station in Stoughton, MA and the construction of two 345 kV pipe-type cables circuits. One cable circuit will run from Stoughton to our Hyde Park station and the second will run from Stoughton to our K Street station. A 345 kV to 115 kV transformer will be installed at both Hyde Park station and K Street station. The first phase of the project is scheduled to be completed by the summer of 2006. The second phase of the project, to be completed in 2007, will add a second cable circuit from Stoughton to K Street station and include an additional 345 kV to 115 kV transformer at K Street station. The Company organization is highly focused on keeping the project on schedule and there is a great degree of confidence that the project will be in-service when it is projected to be.

Q. Please describe the transmission planning process employed by the Company.

A. The transmission planning process used at the Company is consistent with all other transmission-owning utilities as well as being in conformance with NERC,

NPCC and ISO-NE planning practices. The process begins with development of a load forecast for projected peak load demands. Once a peak load demand projection is established for the system an analysis that assesses the performance of the projected system against the criteria used for planning and operating the system is performed. Wherever the system performance fails to meet the established criteria over the ten year planning horizon alternative system upgrades are developed that would serve to mitigate the identified performance violations. These alternative upgrades are then evaluated for their individual cost and performance and those projects that offer the most cost effective solutions are included in the future transmission expansion plans. This process is performed on an annual basis and the plan is updated accordingly. Major projects that are identified in the plan undergo additional analysis to ensure that the performance expectations and design consideration of the proposed upgrades are technically sound and reasonable. The 2006 345 kV Project is one such project. Extensive analysis has been conducted and various reports have been written that demonstrate the need for, performance and design advantages of this project in meeting the reliability needs of the projected Company service territory.

Q. Does the transmission planning process also address area resource adequacy as it relates to transmission supply capabilities?

A. The Company routinely considers the resource adequacy of the supply system serving the Boston Import area as part of its general planning practices. These studies are generally conducted in conjunction with ISO-NE as they affect all load serving entities within the area. These studies consider the projected loads for the

area, the generating resources, and the transmission system supply capabilities under both normal and various abnormal conditions. Generating resource assessments include considerations around the forced outage rates, unit unavailability and unit characteristics (i.e. age, configuration, fuel sources, etc.) for units within the area. The transmission supply capabilities consider the total transmission supply capabilities under normal and extreme operating conditions as prescribed in the Reliability Standards For The New England Power Pool document. The combination of generating resources and transmission resources is assessed to determine the adequacy of supply to meet the projected customer peak load demands under the prescribed adverse operating conditions. Identified deficiencies are addressed through development of alternative supply improvement plans which may include transmission system expansion, generation resource additions and/or customer demand reduction programs.

Q. How do you coordinate your plans with ISO-NE?

A. The Company routinely coordinates its planning activities with those of ISO-NE. The load forecast process is one step in the Company's coordination efforts. ISO-NE and the transmission companies in New England meet on a routine basis to review and coordinate all transmission plans for the New England transmission system. Additionally, joint study efforts between ISO-NE and transmission companies are conducted for major projects that are under consideration. These efforts ultimately lead to the development of the RTEP report produced by ISO-NE each year. The RTEP04 document serves as the most current example of the coordinated planning process employed in New England and includes the 2006

345 kV Project as well as other transmission upgrade projects for the Company's service area.

Q. Please explain how transmission system supply capabilities are determined and what role they play in assessing local area resource adequacy.

A. Determination of the transmission system supply capabilities, particularly for an importing area, are based on assessing the maximum load carrying capability of the set of transmission lines that collectively serve to supply a specific load area. The assessment considers the maximum load that can be supported simultaneously for all transmission system elements that supply the area with the worst case element or worst case two elements out-of-service. This determination essentially assesses the amount of transmission capacity needed to supply the local area loads under single and double contingency conditions. The amount of transmission capacity required has to support the reserve capacity needed to supply the local area loads. These capacity reserves include, running reserves (i.e. generation dispatched on the system to support load in anticipation of a transmission outage), spinning reserves (i.e. additional generation capacity available to the system from running units that are not at full output) and non-spinning reserves (i.e. fast start units such as jet engine driven generators or diesel engine driven generators). For example, the NEMA supply area currently has an "all lines in" transmission system supply capability that is in excess of 6000 MW. Under single worst case contingency conditions this capability is reduced to 3700 MW and under worst case double contingency conditions it is further reduced to 2500 MW. To serve, for example, an area peak load of 5000 MW requires that

1300 MW of generation be available to respond to a single contingency and 2500 MW of generation be available to respond to a second contingency. If sufficient non-spinning generation reserve capacity were available that could start up and produce 1300 MW in less than 15 minutes and if an additional 1200 MW of generation could be brought on to the system within 30 minutes following a transmission import facility outage, there would be no need to run generation in the area. This is not the case, as such resources do not exist. There is only a limited amount of generation that can be brought on to this system (i.e. less than 300 MW) within the 30-minute time window. This results in a requirement during peak load conditions to run additional generation to satisfy the reserve requirement in anticipation of a contingency. Other actions such as "load swapping" and even load shedding can be employed to help meet the reserve requirement necessary to avoid exceeding the transmission system capabilities under contingency conditions but again there is limited availability of these solutions. The consequence during peak load conditions is that a significant amount of generation must be dispatched pre-contingency for the area and the resource adequacy assessment determines if sufficient generation would be available to satisfy the pre-contingency supply requirements. The ability for units to start quickly as well as the ability to ramp up the output of running units is also a primary consideration for ensuring that adequate area supplies are available.

Q. Please explain the "load swap" issue and its importance to the development of proper area supply requirements.

A. Without going into details that are confidential, ISO-NE has the ability to "swap" 50 MW of load from the NEMA/Boston area to rest of pool. It is appropriate to consider the 50 MW NEMA Load Swap in the LICAP model because it is essentially a transmission switching action currently in place that provides Thirty-Minute Operating Reserve (TMOR). The Load Swap is considered on a daily basis as one of several sources of TMOR in support of the ISO's Resource Adequacy Assessment for NEMA, prior to committing a new unit for the purpose of providing thirty-minute reserves. Therefore, the NEMA Load Swap is more than an emergency procedure. It is a real NEMA resource that can be relied upon during the "Critical Hours" defined in ISO-NE's proposal. ISO-NE has improperly not considered the NEMA Load Swap in its local area supply requirements calculations for NEMA.

Q. What has the Company done to address resource adequacy within the NEMA/Boston area ?

A. Since the onset of deregulation the Company has been highly proactive at increasing the ability of its transmission system to serve the area resource requirements of the NEMA/Boston supply area. As early as 2000 the Company put forth a transmission upgrade plan that would add over 500 MVA of new import capability to the system. The upgrades were identified and supported as part of the NEPOOL transmission system upgrades known as the NEMA/Boston Transmission System Upgrades. These upgrades significantly reduced the potential for congestion within the area and historical area energy prices have clearly benefited from these upgrades. While these upgrades were helpful in

relieving the potential for transmission congestion for this part of the system they were only the initial set of solutions needed to meeting the growing dependency on external resources. The Company continues to work extensively on staying ahead of any potential area deficiencies and has directed it efforts toward ensuring that sufficient transmission capacity exists for the area both currently and in the future. The 2006 345 kV Project is clear evidence of this effort and commitment.

Q. What are the future expectations for the Company transmission system?

A. The Company transmission system will be redesigned and reinforced to allow for the changes associated with a market-based generation system while continuing to ensure that local transmission reliability is maintained. The system will continue to be able to accommodate full access to both external and internal generation resources as the market economics are most effective when unconstrained access to a large number of generating units is available. The future transmission system serving the greater Boston area will be designed to address reliability concerns, while at the same time allowing for significant increases in the ability for the system to import power from external areas. The 2006 345 kV Project is a significant step towards meeting these objectives and integrating NEMA/Boston with the rest of NEPOOL. As previously discussed, there are upgrades beyond the 2006 345 kV Project that will continue to ensure that import capabilities for the area keep pace with load growth in the area.

Q. What does this mean in terms of designation of the NEMA/Boston area as a LICAP zone?

A. All of the activities described concerning past and projected expansion of the Boston area transmission system to support area resource adequacy lead to greater availability for the area to access external resources. This improved availability translates to reduced dependency on generating units internal to the area particularly in supplying area energy requirements. The primary roles for units in the area will become the meeting of region-wide demand when dispatched economically and providing local operating reserves. This role is no different than that of any generator on the system serving New England as a whole. Thus, from a reliability perspective, there is no reason for NEMA/Boston to be designated as a separate LICAP zone.

Q. Does this conclude your testimony?

A. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Devon Power LLC, *et al.*) **Docket No. ER03-563-030**

AFFIDAVIT OF WITNESS

I, Charles P. Salamone, being duly sworn, depose and say that the statements contained in the foregoing testimony on behalf of the Attorney General of Massachusetts, *et al.* in this proceeding are true and correct to the best of my knowledge, information, and belief.

Executed on this 3rd day of November, 2004.

Charles P. Salamone

Subscribed and sworn to before me this 3rd day of November, 2004.

Notary Public, State of Massachusetts

My commission expires:

KEITH L. JONES
NOTARY PUBLIC
COMMONWEALTH of MASSACHUSETTS
MY COMMISSION EXPIRES
OCTOBER 9, 2009

WSH\120512.1

TAB 6

Charles P. Salamone
23 Westerly Drive
Bourne, MA, 02532
(508) 759-3489

PROFESSIONAL SUMMARY

Professional Engineer with leadership skills and experience in:

Engineering Staff Supervision	New England Power Pool
Transmission Planning	Substation Planning
Distribution Planning	Meter Engineering
Budget Management	Specification Development
Regulatory Agency Testimony	Software Development
Computer Based Analysis	Data Processing
Congestion Management	Generator Interconnections

EMPLOYMENT BACKGROUND

Director System Planning 2000-Present
NSTAR (Previously Boston Edison and Commonwealth Electric) Boston, MA

- Responsible for long term planning of Company transmission, substation and distribution systems
- Supervise a staff of 9 professional engineers
- Oversee transmission and distribution planning efforts to establish a comprehensive 10 year $300 million system expansion plan
- Serve as Company representative on NEPOOL Reliability Committee and the New England Transmission Expansion Advisory Committee
- Serve as Company expert witness for system planning related regulatory proceedings

Manager, System Planning and Meter Services 1989-1999
Commonwealth Electric Company, Wareham, MA

- Develop risk based prioritized $10 million construction budget procedures
- Supervise a staff of 6 professional engineers and 4 analysts
- Served as chair of the NEPOOL Regional Transmission Planning Committee
- Process billing determinant and interval data for all major system customers
- Develop annual performance analysis reports for all transmission and major distribution systems
- Manage multiple FERC tariff based transmission customer and generation developer system impact studies
- Serve as expert Company witness in State and FERC regulatory proceedings
- Initiated implementation of a risk index for prioritization of all transmission and major distribution construction projects

- Initiated implementation of automated electronic processing of major customer billing data, which significantly reduced time needed to generate bills
- Served as lead member on information technology company merger team
- Implemented process and equipment to perform all tie line, generator and wholesale customer meter testing
- Served as chair of the NEPOOL Planning Process Subcommittee, which established numerous NEPOOL policies for transmission and generator owners
- Served as Vice-Chair of the NEPOOL Reliability Committee

Meter Engineer 1984-1989
Commonwealth Electric Company, Plymouth, MA

- Designed and supervised installation of 15 generator metering and data recorders
- Developed customer load plotting and analysis software
- Developed meter equipment order data processing system for four remote offices
- Implemented PC control of meter test boards, which significantly reduced processing and record keeping time
- Managed programming of all electronic meter registers to insure accurate data registration

Computer Application Engineer 1979-1984
Commonwealth Electric Company, Wareham, MA

- Implemented numerous technical and analytical software applications for engineering analysis
- Served as member of decision team for implementation of a new SCADA system

Planning Engineer 1978-1979
San Diego Gas & Electric Company, San Diego, CA

- Performed extensive stability analysis for a new 230 kV transmission interconnection with Mexico
- Performed transmission design and performance analysis for a new 250 mile 500 kV line from San Diego to Arizona

Planning Engineer 1973-1978
New England Gas & Electric Company, Cambridge, MA

- Performed extensive stability analysis for a new 560 MW generating plant on Cape Cod
- Developed transmission plan for a new 345 kV transmission line on Cape Cod
- Developed plans for design and sighting of new 115 / 23 kV substations on Cape Cod

EDUCATION

Massachusetts Professional Engineer License #36499, 1992
B.S.E.E, Power System Engineering, 1973
Gannon University, Erie, PA

TAB 7

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Devon Power LLC, *et al*.	**)**	**Docket No. ER03-563-030**
	)	

AFFIDAVIT OF
GLENN E. HARINGA
GENERAL ELECTRIC INTERNATIONAL, INC.
POWER SYSTEMS ENERGY CONSULTING

Q. Please state your name and business address.

A. My name is Glenn Haringa. I am a Consulting Engineer in the Energy Consulting group of GE Energy. My business address is Building 2, room 637, 1 River Road, Schenectady, New York 12345.

Q. Please describe your education and professional background.

A. I have a Bachelor's degree and Master's degree in Electrical Engineering from Worcester Polytechnic Institute. I have over 28 years of experience in generation system planning. I led the development of GE's Multi-Area Reliability Simulation (MARS) program in the late 1980's and have been responsible for its on-going development, support, and application since then. I am also involved in the support and application of GE's Multi-Areas Production Simulation (MAPS) software.

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

A. I have been employed by NSTAR Electric and Gas Corporation ("NSTAR"), on behalf of a larger coalition of stakeholders in this proceeding, for the purpose of calculating the local sourcing requirements ("LSRs") for all of the ICAP regions proposed in ISO-NE's August 31, 2004 LICAP filing. The purpose of this affidavit is to briefly describe the methodology that was used to calculate the LSRs and to certify the accuracy and validity of the results.

Q. Please describe the scope of the analysis performed by GE for this proceeding.

A. The analysis consisted of performing a number of MARS simulations to determine the additional load carrying capability ("ALCC") for the CT and NEMA sub-area for the study years 2006 through 2010. The methodology used was the same as described on page 39 of the direct testimony of David LaPlante (filed on August 31, 2004). NEPOOL was modeled as two regions: the sub-area of interest and the rest of the pool. The only transmission constraints modeled were those between the sub-area of interest and the rest of the pool. Capacity was then removed from the sub-area of interest until the NEPOOL LOLE just meets one day in ten years.

Q. What was the source of all inputs used in your analysis?

A. The input data for the MARS simulations was taken from the Protected Data CD in the CTL Confidential directory. The CD with the directory \MARS

runs\LaPlante – MARS Runs was the source of the hourly load shapes used by MARS. This data was for study year 2005.

Q. Please describe any assumptions used in your analysis that were not obtained from sources prepared by ISO-NE.

A. In order to simulate study years 2006 through 2010, the data obtained from sources prepared by ISO-NE were modified as follows:

- the load shapes were adjusted through time using the sub-area peak load forecast (Reference Weather Peaks) from the web-site referenced on page 5 of the RTEP04 Draft Appendices 8-30-04;

- the transfer limits between sub-areas were updated according to Table 5.1 of the RTEP04 Draft Technical Report 8-30-04;

- the following unit installations and retirements were added:

    - Kleen Energy combined cycle unit installed in CT sub-area June 2006

    - Kendall Steam 1, combustion turbine, and Jet 2 retired January 2005

    - New Boston 1 retired in June 2006

Q. Were you able to tie your results to ISO-NE's results when the same input assumptions were used?

A. Using the data described above, I was able to duplicate ISO-NE's results for study year 2005.

Q. Does this conclude your affidavit?

A. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Devon Power LLC, *et al.*) **Docket No. ER03-563-030**

AFFIDAVIT OF WITNESS

I, Glenn Haringa, being duly sworn, depose and say that the statements contained in the foregoing testimony on behalf of the Attorney General of Massachusetts, *et al.* in this proceeding are true and correct to the best of my knowledge, information, and belief.

Executed on this 3RD day of November, 2004.

Glenn Haringa

Glenn Haringa

Subscribed and sworn to before me this 3rd day of November, 2004.

Richard F. Wilson

Notary Public, State of New York

RICHARD F. WILSON
NOTARY PUBLIC - STATE OF N.Y.
QUALIFIED SCHENECTADY COUNTY
NO. 4682660
COMMISSION EXPIRES JANUARY 12, 2007

My commission expires:

JANUARY 12, 2007

CERTIFICATE OF SERVICE

I hereby certify that the foregoing instrument is being served upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C., this 4th day of November, 2004.

Stephen L. Teichler