UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and New England Power Pool	))	**Docket No. ER08-1209-000**

PROTEST OF FIRSTLIGHT COMPANIES AND NRG COMPANIES

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Pursuant to Rule 211 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"),[1] the FirstLight Companies ("FirstLight") and the NRG Companies ("NRG")[2] submit this protest of the tariff revisions filed by ISO New England Inc. ("ISO-NE") and the New England Power Pool Participants Committee ("Participants Committee" and, with ISO-NE, the "Filing Parties") in the above-captioned matter to pay generation capacity resources only their "net risk adjusted going forward costs" when their Static or Dynamic De-List Bids in a Forward Capacity Auction ("FCA") are rejected for reliability reasons (hereinafter referred to as "Filing Parties' Proposal").[3]

The Filing Parties' Proposal to pay a resource whose Static or Dynamic De-List Bid is rejected for reliability only its "net risk adjusted going forward costs" is unjust, unreasonable, confiscatory and must be rejected because it:

- Does <u>not</u> reflect the bid such resource would submit in a competitive, *long-run*

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1 18 C.F.R. § 385.211 (2008).

2 The First Light Companies are: FirstLight Power Resources Management, LLC, FirstLight Hydro Generating Company, and Mt. Tom Generating Company, LLC. The NRG Companies are: NRG Power Marketing LLC, Connecticut Jet Power LLC, Devon Power LLC, Middletown Power LLC, Montville Power LLC, Norwalk Power LLC ("Norwalk") and Somerset Power LLC. FirstLight and NRG filed their separate electronic motions to intervene on July 14, 2008.

3 Tariff Revisions Relating to Resources Needed for Reliability in the Forward Capacity Market, Docket No. ER08-1209-000 (July 1, 2008) ("Filing Parties' Transmittal Letter"). *See* Proposed Section III.13.2.5.2.5.1 to Market Rule 1 of the ISO-NE FERC Electric Tariff No. 3 (Filing Parties' Transmittal Letter at Attachment 4).

market like the Forward Capacity Market ("FCM") where the obligation is three-years forward;

- Does not compensate the resource for the locational value of the local reliability service it is being compelled to provide;
- Does not provide older less efficient resources – like Norwalk Units 1 and 2 – with a reasonable opportunity to recover their long-run average costs including a return of and on capital;
- Will likely result in such older, less efficient resources not even recovering the cash outlays needed to operate;
- Does not constitute a competitive, market-based mechanism for resolving local reliability compensation issues for which the De-List Bid was rejected; and
- Does not send the appropriate price signal to incent transmission or new capacity solutions and efficient planning and construction of the transmission system.

The Filing Parties' Proposal does not satisfy their burden under Section 205 of the Federal Power Act ("FPA") to submit a just and reasonable rate, and is contrary to long-standing Commission precedent that a just and reasonable rate must: (1) compensate resources for the locational value of the reliability service they provide; (2) provide a reasonable opportunity for the resource to recover its full costs and earn a fair return; and (3) should incent timely and economic transmission or generation solutions to resolve reliability problems. Moreover, the FCM Settlement requires that the Commission – not ISO-NE – determine a just and reasonable rate of compensation for resources whose Static and Dynamic De-List bids are rejected for reliability purposes. Accordingly, the Commission should reject the Filing Parties' Proposal as not just and reasonable and, instead, direct ISO-NE to develop and submit a market-based mechanism, like the NRG Proposal described herein, for compensating resources whose Static or Dynamic De-List Bids are rejected for reliability

I. SUMMARY OF PROTEST

A. Executive Summary

The Filing Parties' Proposal is not just and reasonable, and must be rejected, because it bases compensation on ISO-NE's flawed formula, which understates a resource's avoidable costs, which is contrary to the fundamental economic principle that, in a competitive long-run market with new entry, such as the FCM, resources would bid at their long-run average costs – not their avoided costs. Independently, the Filing Parties' Proposal is unjust and unreasonable because it fails to appropriately compensate resources with rejected Static or Dynamic De-List Bids for the locational market-based value of the reliability service they are compelled to provide. Instead of compensating resources for the market value of the reliability service they are compelled to provide, by virtue of their not being allowed to de-list, the Filing Parties' Proposal arbitrarily limits such resources to administratively-determined payments, based on bids capped at their avoided costs, which do not compensate the resources for the actual costs of providing reliability service during the Commitment Period.

As a result, the Filing Parties' Proposal may not, and in the case of certain resources like NRG's Norwalk Units 1 and 2 will not, provide resources with rejected Static and Dynamic De-List Bids with a reasonable opportunity to recover their long-run average costs, and is, therefore, confiscatory and prohibited under Sections 205 and 206 of the FPA. As a just and reasonable alternative, FirstLight and NRG urge the Commission to adopt NRG's proposal to the NEPOOL Participants Committee ("NRG Proposal") for using annual reconfiguration auctions ("Local Reconfiguration Auctions") to determine the least-cost means of resolving the local reliability violation and establish a market-based price that provides a reasonable opportunity for a resource with a rejected Static or Dynamic De-List Bid to recover its long-run average costs and reflects the locational value of the reliability service that such resource is being required to involuntarily provide.

If the Commission does not adopt the NRG Proposal, then it should either allow owners of resources with rejected Static and Dynamic De-List Bids to seek compensation through cost-of-service, Reliability Must-Run ("RMR") agreements or, at a minimum, allow NRG the option to change the status of Norwalk Units 1 and 2 to "Rejected Permanent De-List" for purposes of this first Commitment Period, and give any other resources that did not submit permanent De-List Bids for the second FCA the option to do so, in light of the potential unfairness of subjecting such resources to the Filing Parties' Proposal after they have already made bidding decisions.

B. Extended Summary

- **The Filing Parties' Proposal Fails To Compensate Resources With Rejected De-List Bids Consistent With The Economic Theory Underlying A Long-Run, Forward Market Like The FCM.**

The Filing Parties' Proposal further fails to provide just and reasonable compensation because it is based on the flawed economic assumption that resources will always bid their avoidable short-run marginal costs.[4] The Filing Parties ignore the fact that the FCM is a long-run, forward market. In the long run where there can be new entry, generally accepted economic theory clearly indicates that prices in competitive markets are expected to converge on long-run average costs, including a return of and on capital. Therefore, resources whose bids are rejected for reliability reasons should be compensated based on their own long-run average costs or the cost of new entry.[5]

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[4] The FCM Market Rules characterize the proposed payments to resources with rejected Static and Dynamic De-List Bids as equal to their "net risk adjusted going forward costs." Filing Parties' Transmittal Letter at 13. However, these "net risk adjusted going forward costs" are not the resources' actual going forward costs, which would be their fixed and variable costs to provide reliability service for the Commitment Period without depreciation or an equity return on capital. Instead, "net risk adjusted going forward costs" are ISO-NE's estimate of the costs that the resource could avoid three years in the future if they were to de-list from the FCM and deactivate (mothball) the resource for a one year Commitment Period. For purposes of discussion, the concepts of "short-run marginal costs" and "net risk adjusted going forward costs" are used interchangeably. However, as discussed in Section V.B.5, flaws in the ISO-NE formula for computing "net risk adjusted going forward costs" result in them being less than even short-run marginal costs.

[5] *See* Affidavit of Jonathan A. Lesser, Ph.D. and David W. DeRamus, Ph.D. on Behalf of the NRG Companies ("Lesser-DeRamus Affidavit") at 10:7-12, n.14 (citing F.M. Scherer & David Ross, <u>Industrial Market Structure and Economic Performance</u> 19-20 (3rd ed., 1990) (in long-run equilibrium, "[n]ew firms attracted by the profit lure will enter the industry, adding

The Filing Parties also erroneously rely on highly simplified models of economic theory, based on hypothetical assumptions of "perfect competition," to justify compensating resources whose Static and Dynamic De-List Bids are rejected for reliability based on their short-run marginal costs. Absent hypothetical conditions of perfect competition, even suppliers in short-run markets will bid above their short-run marginal costs, and this is true in all real world markets. Compensating resources needed for reliability based on their short-run marginal costs – particularly in long-run markets such as the FCM – is not supported by sound economics, undercuts price signals needed to incent new entry, and subsidizes the failure to properly plan and construct the transmission system to prevent such reliability problems. Given the three-year planning period under FCM, there are no sound economic reasons why resources with rejected De-List Bids should be required to provide such subsidies. In fact, it would be economically irrational for a resource to agree to provide service over the long-run at a price that provides absolutely no return of or return on its capital.

Moreover, while a resource may voluntarily choose to bid its short-run marginal costs in a uniform price auction where the resource expects to be selected and then receive a clearing price that will provide it with inframarginal revenues, a generator in an as-bid market will bid at what it estimates the market clearing price to be. Thus, a resource that does not expect to be able to earn inframarginal revenues in the energy and ancillary services markets, and knows that it will be paid only its De-List Bid if it is needed for reliability, would not bid its short-run marginal costs. Instead, it would bid the higher of its long run average costs or an amount just below the expected bid of the lowest cost new entrant. Bidding anything less would result in the

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their new marginal cost functions to the industry's supply curve, and existing firms will expand their capacity, so the industry supply curve shifts to the right. Entry and expansion will continue, augmenting output and driving the price down, until price has fallen into equality with *average total cost (ATC) for the representative firm...(including the minimum necessary return on its capital*"*)* (emphasis added)).

resource not recovering its own long-run averages costs or the value, if any, associated with the difference between its long-run average costs and those of the next new entrant. As the results of the first FCA demonstrate, capacity resources with rejected De-List Bids are likely to be those with high operating costs and low capacity factors (like NRG's Norwalk units). As a result, these units will earn little or no inframarginal revenues in the energy market and the Filing Parties' Proposal will not provide those types of resources with a reasonable opportunity to recover their long-run average costs, including a return of and on capital, from the market, despite the fact that they are highly valuable to the system for the security or other reliability service that they provide.

- **The Filing Parties' Proposal does not compensate the option value that ISO-NE and Consumers get from being able to reject de-list bids for reliability.**

The Filing Parties' witnesses, Mr. LaPlante and Mr. Schnitzer, also mischaracterize the submission of Static and Dynamic De-List Bids as the resource's purchasing an "option" to stay in the capacity market, rather than permanently de-list. In fact, to the contrary, it is ISO-NE who is getting the "option" because an existing generation resource is *compelled* to either participate in the FCM as a price-taker or submit a De-List Bid, the latter of which ISO-NE may reject for local system security or other reliability reasons, thereby precluding it from leaving the FCM even though its capacity is not needed to clear the resource adequacy requirements of the FCA. In doing so, the FCM Market Rules dispense with an essential element of a competitive market – freedom to exit – and give ISO-NE the "option" to call on any existing resource that it determines is needed for local system security reliability. This option has value to the customers who use or rely on the ISO-operated transmission system, and that value is substantially more than the short-run marginal costs of the resource whose De-List Bid is rejected. The value of this option is equal to the lower of the cost of replacing the reliability benefit of the resource to the system (through transmission system upgrades or new generation), or the expected cost to the transmission system in the event that the resource with the rejected De-List Bid were not available to maintain system security.

Thus, the Filing Parties' Proposal to compensate resources with rejected Static or Dynamic De-List Bids at substantially less than their long-run average costs (i.e., their "net risk adjusted going forward costs") is not based on sound economic principles, does not provide a reasonable opportunity for such resources to recover their long-run average costs and is, therefore, unjust and unreasonable. Moreover, the Filing Parties' Proposal is impermissibly discriminatory insofar as it provides an arbitrarily higher level of compensation to Permanent De-List Bids than to Static and Dynamic De-List Bids for the same reliability service. A competitive market should produce a uniform market clearing price based on the locational value of the service being provided, and not based on the short-run marginal costs of the resources providing the service.

- **The Filing Parties' Proposal does not compensate resources like Norwalk Units 1 and 2 for the costs they must cover to continue in operation.**

Setting aside the flawed economic theory underpinning the Filing Parties' Proposal, the formula used by ISO-NE to calculate "net risk adjusted going forward costs" is patently unjust and unreasonable because it will not provide resources that are unable to earn meaningful inframarginal revenues in the energy and ancillary services markets (like Norwalk Units 1 and 2) with sufficient compensation to continue in operation. The formula recovers only those expenses that can be avoided by de-listing for one year. Therefore, it excludes altogether many of the going forward costs which generators must pay to remain in business and provide reliability service such as property taxes, insurance, capital additions needed due to wear and tear of providing reliability service, and a substantial portion of a resource's full labor costs. In addition, ISO-NE's formula neither provides resources with return of or return on capital, nor compensates them directlyfor costs associated with the significant business and financial risks to the resource, and thus could result in the resource not recovering its fixed costs and having to shut down. Such business risks include the potential to incur substantial real-time replacement power costs, significant reductions in FCM payments due to forced outages during shortage hours, and hefty insurance deductibles in the event of an insured loss during operations. ISO-NE's formula also does not compensate resources for the risks associated with having to comply with future laws and regulations affecting operations – particularly, environmental laws and regulations related to reducing Nitrogen Oxide ("NOx"). The costs associated with these risks, for the most part, could be avoided by de-listing and are inordinately greater because the resource is being forced to accept a year-long commitment to operate three years hence, as compared to a resource in a short-term market that is being required to operate the next hour or next day.

Moreover, ISO-NE's formula does not even provide an accurate measure of short-run marginal costs. For example, a resource's market clearing prices and inframarginal revenues ("IMR") can vary greatly from year to year, making it unlikely that the historical data used to construct the going forward costs in Static or Dynamic De-List Bids will bear any relationship to the IMRs that will be earned during the Commitment Period three years hence. This is particularly true for Norwalk, whose historical IMRs reflect Peaking Unit Safe Harbor ("PUSH") bidding which was discontinued in June 2007. Finally, the inflation adjustment used by ISO-NE will likely understate the impact of inflation on costs, because the adjustment relies on data from more than three years prior to the Commitment Period.

- **The Filing Parties' Proposal Does Not Appropriately Compensate Resources With Rejected Static Or Dynamic De-List Bids For The Locational Value Of The Local Reliability Service They Are Compelled To Provide.**

Setting aside the failure to compensate resources in a manner consistent with a long-run forward market, the Filing Parties' Proposal does not appropriately compensate resources with rejected Static or Dynamic De-List Bids for the locational value of the local reliability service they are compelled to provide because neither the FCA clearing prices nor the rejected De-List Bids reflect the local system security need for which ISO-NE rejects the De-List Bids. This is because the FCM procures and compensates for capacity needed to satisfy resource adequacy reliability standards, but ISO-NE rejects De-List Bids based on much more stringent local system security and reliability requirements. As a result, FCA clearing prices are much lower than they would be if the FCA were designed to procure capacity resources needed to meet system security and other local reliability requirements and, thus, do not reflect the locational value of the resources whose De-List Bids are rejected in order to meet those requirements.

Moreover, because the Filing Parties' Proposal limits resources with rejected Static or Dynamic De-List Bids to compensation at the lower of their De-List Bids or their "net risk adjusted going forward costs," those resources are not compensated for the locational value they are required to provide to ensure system security. Resources that have high variable operating costs and low capacity factors will earn little or no inframarginal revenues from the energy market and must, therefore, depend upon the capacity market for recovery of fixed costs and a return on investment.[6] As a result, the Filing Parties' Proposal will not afford these resources a reasonable opportunity to recover their long-run average costs. As the rejection of Norwalk's

[6] Moreover, if the transmission system fails to keep pace with changes in load and generation patterns and too many units are retained for local system security requirements, energy prices will be depressed and inframarginal revenues will drop. If this occurs, even resources which run more often in the energy market may not have a reasonable opportunity to recover their fixed and variable costs and earn a return.

Dynamic De-List Bids in the first FCA demonstrates, these are precisely the type of resources that are likely to submit Static or Dynamic De-List Bids.

- **The NRG Proposal To Use Local Reconfiguration Auctions Is A Just And Reasonable, Market-Based Solution To The Reliability Compensation Issues In This Proceeding**

Instead, as a just and reasonable alternative to the Filing Parties' Proposal, FirstLight and NRG urge the Commission to direct ISO-NE to implement NRG's proposal for using Local Reconfiguration Auctions to: (1) incent either transmission solutions or new resource entry that will allow a resource with a rejected Static or Dynamic De-List Bid to de-list; or (2) establish a market-based mechanism for price formation that reflects the locational value of system security reliability service that a resource with a rejected Static or Dynamic De-List Bid is being required to involuntarily provide. The NRG Proposal is designed to produce a market price that most accurately reflects the locational value of the system security being provided, is consistent with the Commission's preference for market-based solutions, and obviates concerns about so-called "toggling" between the higher of market or cost-of-service rates. By comparison, the Filing Parties' Proposal fails to provide any process to incent transmission upgrades or new resource entry needed to resolve the locational reliability concern, and in fact provides a strong disincentive by artificially suppressing payments to resources needed for local security and reliability far below the value of those services. In addition, the Filing Parties' Proposal relies on administrative pricing rather than market-based pricing and is, therefore, flatly inconsistent with the Commission's preference to rely on market solutions. If the Commission does not require ISO-NE to adopt the NRG Proposal, or comparable market-based mechanism, it should allow resources whose Dynamic or Static De-List Bids are rejected for local reliability to seek cost-of-service RMR agreements with ISO-NE.

- **Retroactive Application Of The Filing Parties' Proposal To Affected Resources In The First And Second FCAs Is Fundamentally Unfair And Must Be Addressed**

In the event that the Commission chooses to adopt the Filing Parties' Proposal, the Commission should, at a minimum: (1) give NRG an option to change the status of Norwalk Units 1 and 2 to "Rejected Permanent De-List" for purposes of the first Commitment Period so it can pursue cost-of-service compensation under the Filing Parties' Proposal; and (2) give any other resources that did not submit Permanent De-List Bids for the second FCA the option to do so within thirty (30) days of the Commission's order. Principles of fundamental fairness and equity require that the Commission grant such relief in this case. The FCM Settlement requires that generators whose Static or Dynamic De-List Bids are rejected for reliability be paid a "just and reasonable compensation rate as determined by the Commission."[7] At the time it submitted its bids in the first FCA, NRG did not know the criteria that would be used to reject Static and Dynamic De-List Bids in the first FCA, and ISO-NE had not revealed the substance of the Filing Parties' Proposal, so NRG had no way of knowing that the "just and reasonable" compensation would be its "net risk adjusted going forward costs," which are only a fraction of its true going forward costs and its long-run average costs. Similarly, there may be other resources that desire to submit Permanent De-List Bids in the second FCA in lieu of Static or Dynamic De-List Bids as a result of the Commission's decision in this proceeding.

[7] *ISO New England Inc.*, 119 FERC ¶ 61,045 at P 57 (2007) ("*FCM Market Rules Order*") (citing Market Rule 1 at § 13.2.5.2.5(b)).

II. BACKGROUND

C. The History Of Reliability Compensation Issues In ISO-NE Demonstrates The Need To Appropriately Compensate The Locational Value Of Capacity For The Specific Reliability Services Resources Provide.

In 1998, ISO-NE moved from meeting its reliability needs through an installed capacity ("ICAP") requirement to a bid-based ICAP market.[8] In response to the Commission's identification of shortcomings in the bid-based ICAP market and the non-locational, single-settlement energy market, ISO-NE and NEPOOL began in 2000 to develop a standard market design ("SMD") that could replace the existing ISO-NE market rules with a comprehensive Market Rule 1.[9] On September 20, 2002, the Commission accepted SMD for New England as superior to the then-current market design, but directed further revisions, including development of a locational component to the ICAP market to "ensure that capacity resources are located where it is most efficient," while compensating those resources via an "efficient and workable" method.[10] Under Market Rule 1, ISO-NE may designate resources needed for reliability as RMR Resources who may apply for compensation under cost-of-service contracts.[11]

In 2003, NRG filed four cost-of-service RMR agreements for generating capacity in the Southwest Connecticut ("SWCT") Designated Congestion Area ("DCA"). The Commission rejected NRG's (and other generators') RMR agreements, urging ISO-NE to "incorporate the effect of those agreements into a market-type mechanism," instead of relying on stand-alone

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8 *See New England Power Pool*, 83 FERC ¶ 61,045, 61,263 (1998).

9 *See New England Power Pool and ISO New England, Inc.*, 100 FERC ¶ 61,287 at P 2 and n.4 (2002) ("*NE-SMD Order*"), *order on reh'g*, 101 FERC ¶ 61,344 (2002) ("*SMD Rehearing Order*").

10 *Id*. at PP 27, 101.

11 ISO New England Inc. FERC Electric Tariff No. 3, Section III, Appendix A, 3rd Revised Sheet No. 7461 at § 2.3.1(a).

agreements that might suppress market clearing prices.[12] Nonetheless, the Commission found that the absence of a location-specific capacity or deliverability requirement in New England "may not allow suppliers in DCAs an adequate opportunity to recover their costs and that a location-specific capacity requirement must be in place,"[13] and directed ISO-NE to institute revised bidding rules (PUSH bidding) to give low-capacity factor generating units operating in designated congestion areas the opportunity to recover their fixed and variable costs through market bids.[14]

Additionally, the Commission directed ISO-NE to develop a permanent mechanism to implement a location-based or deliverability requirement in the ICAP or resource adequacy market, "so that capacity within DCAs may be appropriately compensated for reliability."[15] With all but its Norwalk station unable to recover the costs of its facilities via the PUSH bidding mechanism, NRG once again filed RMR agreements in early 2004.[16] On March 22, 2004, the Commission accepted the NRG RMR agreements for filing, set the rates included in the agreements for hearing, and conditioned them to terminate on the date that a location installed capacity ("LICAP") market or deliverability requirement was implemented in accordance with *Devon II*.[17] The Commission reasoned that accepting the agreements for a limited term was appropriate given that the PUSH mechanism did not provide these older units with sufficient

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12 *See Devon Power LLC*, 102 FERC ¶ 61,314 ("*Devon I*"); *Devon Power LLC*, 103 FERC ¶ 61,082 at P 29 ("*Devon II*"), *reh'g granted in part and denied in part*, 104 FERC ¶ 61,123 (2003) ("*Devon III*"); *PPL Wallingford Energy LLC*, 103 FERC ¶ 61,185, *reh'g granted in part and denied in part*, 105 FERC ¶ 61,324 (2003) ("*PPL Wallingford*").

13 *Devon II* at P 31.

14 *See Devon II* at P 33; *Devon III* at PP 25-31.

15 *Devon II* at P 37.

16 *See Devon Power LLC*, 106 FERC ¶ 61,264 at P 4 (2004) ("*Devon IV*").

17 *Id*. at P 1.

revenues to recover their costs.[18] While the Commission stressed its continued commitment to "implementation of a market-based mechanism to appropriately compensate generators providing reliability services," it found that RMR contracts were nevertheless required until implementation of the LICAP mechanism to ensure that generators providing reliability services would be able to adequately recover revenues and participate in the "functioning market" once it was implemented.[19]

On March 1, 2004, ISO-NE filed a proposed LICAP mechanism for implementation by June 1, 2004.[20] As proposed, the LICAP mechanism would have added a locational element to the ICAP markets by establishing four regions with separate ICAP requirements and prices: Maine, Connecticut, Northeast Massachusetts/Boston, and the remainder of New England.[21] In an order issued on June 2, 2004, the Commission agreed with the broad concepts in ISO-NE's LICAP proposal, found that additional revisions were necessary prior to its implementation, delayed implementation of LICAP until January 1, 2006, and set specific elements of the LICAP proposal for hearing.[22] In particular, the Commission expressed concern that the specific regions proposed by ISO-NE did not adequately reflect the areas where infrastructure investment was needed, especially with regard to the constrained region of SWCT.[23] The Commission extended the PUSH mechanism for the interim, and stated that it would also consider RMR contracts "to

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18 *Id*. at P 18.

19 *See id.* at P 28.

20 Compliance Filing of ISO New England Inc., Docket No. ER03-563-030 (Mar. 1, 2004).

21 ICAP obligations are imposed on load serving entities, requiring them to procure a specified amount of ICAP each month to ensure that there is sufficient capacity to supply system peak load under various contingencies.

22 *Devon Power LLC*, 107 FERC ¶ 61,240 at PP 1-2, 45 ("*Devon V*"), *order on reh'g and clarification*, 109 FERC ¶ 61,154 (2004) ("*Devon VI*"), *order on reh'g and clarification,* 110 FERC ¶ 61,315 (2005).

23 *Devon V* at P 2.

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ensure that market participants are appropriately compensated for reliability services in the short-term."[24]

On June 15, 2005, following more than a year of hearing procedures, the Presiding Judge issued an Initial Decision on the issues set for hearing in *Devon V*.[25] The Initial Decision largely (but with some variation) adopted the revised LICAP market design proposed by ISO-NE in its August 31, 2004 initial testimony.[26] While several parties to the proceeding disagreed as to whether ISO-NE's LICAP proposal should address security (i.e., meeting short-term system emergencies) as well as resource adequacy concerns,[27] the Presiding Judge generally found the LICAP market design to be just and reasonable and to appropriately address resource adequacy needs.[28]

D. The FCM Settlement Established a Long-Run, Forward Capacity Market For Resource Adequacy Where New Entry Is Supposed To Both Set And Discipline Prices.

On March 6, 2006, a group of settling parties filed the FCM Settlement resolving all issues in the LICAP proceeding.[29] On June 16, 2006, the Commission accepted the FCM Settlement.[30]

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24 *Id.* at PP 4, 72.

25 *Devon Power LLC*, 111 FERC ¶ 63,063 (2005) ("*LICAP Initial Decision*").

26 *LICAP Initial Decision* at PP 747, *et seq*.

27 *See, e.g., id.* at PP 200-201 (recounting Calpine's argument that security is a subset of reliability and must be addressed in the ICAP proposal), P 307 (relaying the CT Parties' argument that LICAP properly addresses resource adequacy and not security).

28 *See id*. at P 741.

29 Settlement Agreement Resolving All Issues, Docket Nos. ER03-563-030, *et al*. (Mar. 6, 2006) ("FCM Settlement").

30 *Devon Power LLC*, 115 FERC ¶ 61,340 ("*FCM Order I*"), *order on rehearing and clarification*, 117 FERC ¶ 61,133 (2006) ("*FCM Order II*"), *aff'd in part and rev'd in part, Maine Pub. Util. Comm'n, v. FERC*, 520 F.3d 464 (D.C. Cir. 2008).

Under FCM, ISO-NE procures capacity for New England's load through an annual descending clock FCA. The auctions are held three-plus years ahead of the Commitment Period in order to provide for a planning period for new entry and thereby allow new capacity (both generation and demand response capacity resources) to compete in the auctions.[31] The Commitment Period is a year-long period that corresponds to the ISO-NE power year. The first Commitment Period during which capacity suppliers will begin receiving payments pursuant to the FCM auction mechanism begins on June 1, 2010.

Under the FCM Settlement, existing generation capacity resources are required to participate in the FCA as price-takers.[32] An existing capacity resource is paid the clearing price for resource adequacy service in the FCA (subject to certain adjustments provided for by the FCM Settlement and ISO-NE Market Rules) and is obligated to make its capacity available for the Commitment Period and to offer its capacity into the Day-Ahead and Real-Time energy markets.[33] An existing capacity resource can only seek to avoid these obligations by submitting a De-List Bid in the FCA.[34] If the Capacity Clearing Price in the FCA falls below the level of a De-List Bid, the owner of that existing capacity resource is allowed to de-list all or a portion of the Resource, unless ISO-NE determines that the Resource is needed for reliability.[35]

There are four types of De-List Bids – Permanent De-List Bids, Static De-List Bids, Export Bids, and Administrative Export De-List Bids – which must be submitted to ISO-NE during the qualification process in advance of the FCA.[36] A fifth type of De-List Bid – Dynamic

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31 *FCM Order I* at P 16.

32 *See* Filing Parties' Transmittal Letter at 12.

33 FCM Settlement at § 11, Part IV.A1.

34 FCM Settlement at § 11, Part III.D.5. *See also, FCM Market Rules Order* at P 32.

35 *Id.* at P 54.

36 *See also* Market Rule 1 at § 13.1.2.3.1.1.

De-List Bids – may be submitted during the FCA. The ISO-NE's Market Monitor reviews each Static De-List Bid and Export Bid above 0.8 times the Cost of New Entry ("CONE"),[37] and each Permanent De-List Bid above 1.25 times CONE, submitted by existing generating capacity resources.[38] The Market Monitor reviews such De-List Bids to determine whether the bid is consistent with the resource's "net risk adjusted going forward costs" (and opportunity costs in the case of exports).[39] If the Market Monitor determines that the De-List Bid is inconsistent with the resource's "net risk adjusted going forward costs" (and opportunity costs in the case of exports), that De-List Bid will be rejected and the Market Monitor will indicate to the resource owner and to the Commission what price level the Market Monitor determines is appropriately representative of the resource's "net risk adjusted going forward costs." The resource owner may accept the Market Monitor's determination, or may challenge the finding before the Commission.[40] Dynamic De-List Bids may be submitted in any FCA round when the price drops below 0.8 times CONE.[41]

Where ISO-NE determines that some or all of the capacity associated with a De-List Bid is needed for reliability reasons, then that De-List Bid will not clear in the FCA, and the De-List Bid will neither be accepted nor set the Capacity Clearing Price.[42] The FCM Settlement expressly provides that, when a De-List Bid is not accepted, "the ISO shall attempt to procure replacement capacity at each FCA and annual reconfiguration auctions in order to release the

[37] CONE for the First FCA was administratively determined to be $7.50/kW-month and, thereafter, will be adjusted in accordance with the FCM Market Rules. CONE for the Second FCA will be $6.00/kW-month.

[38] Market Rule 1 at § 13.1.2.3.2.

[39] *Id*.

[40] *Id*.

[41] Market Rule 1 at § 13.2.3.2(d).

[42] Market Rule 1 at § 13.2.5.2.5.

capacity Resource to de-list."[43] However, if the reliability concern that prompted ISO-NE to reject the De-List Bid has not been addressed following the last annual reconfiguration auction for the relevant Commitment Period, then the capacity resource will become a listed resource for the Commitment Period.[44] In such circumstances, the FCM Settlement requires that the resource will be entitled to "just and reasonable compensation."[45] In approving the Market Rules governing the mitigation to be applied to the different categories of De-List Bids, the Commission expressly declined to address the question of what would constitute just and reasonable compensation in the event those De-List Bids were rejected for reliability.[46]

E. NRG's Norwalk Units 1 And 2 Have High Costs, Low Capacity Factor For Which The FCM Alone Does Not Provide A Reasonable Opportunity To Recover Their Long-Run Costs.

Norwalk Units 1 and 2 are emblematic of the Commission's efforts to address reliability compensation issues in New England and demonstrate, notwithstanding the implementation of FCM, that further market-design changes are needed to ensure that resources needed for reliability have a reasonable opportunity to recover their long-run average costs, or are replaced by lower-cost transmission and/or capacity solutions. Norwalk was one of the four NRG generating facilities to unsuccessfully seek RMR agreements in 2003, and operated using PUSH bidding from June 2003 until June 2007, when PUSH bidding was terminated by the Commission. In April 2007, as a replacement for PUSH bidding, Norwalk filed a RMR

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43 FCM Settlement at § 11, Part III.K.

44 *FCM Market Rules Order* at P 57 (citing at Market Rule 1 at § 13.2.5.2.5(b)). As part of the ISO-NE Proposal, the Participants Committee approved changes to Market Rule 1 that would result in a capacity Resource with a rejected De-list Bid becoming a listed Resource for the Commitment Period if ISO-NE does not notify the Resource that it is no longer needed for reliability by midnight on June 1 of the year preceding the Commitment Period for which the De-List Bid was rejected. *See* Proposed Amendment to Market Rule 1, § 13.2.4.2.4.1(2)(ii).

45 *FCM Market Rules Order* at P 57 (citing Market Rule 1 at § 13.2.5.2.5(b)).

46 *Id*. at P 85.

agreement with ISO-NE. The Commission conditionally accepted the RMR agreement effective June 17, 2007, subject to refund, and set it for settlement procedures and, if necessary, an evidentiary hearing.

In the first FCA held in February 2008, Norwalk Units 1 and 2 submitted Dynamic De-List Bids of $5.999/kW-month (the maximum Dynamic De-List Bid allowed under the FCM Settlement).[47] Notwithstanding the fact that the first FCA was halted only when the clearing price hit the $4.50/kW-month floor specified in the FCM Settlement, ISO-NE rejected Norwalk's Dynamic De-List Bids on the basis that both units were needed for system security. As a result, Norwalk will become the first facility to be compensated for reliability under the rules established in this proceeding, unless the ISO-NE determines prior to June 1, 2009, that Norwalk is not needed for reliability.

Norwalk Unit 1 is an approximately 164 MW oil-fired unit and Unit 2 is an approximately 172 MW oil-fired unit. Units 1 and 2 entered service as coal-fired units in 1960 and 1963, respectively, and were converted to operate on No. 6 fuel oil in 1971 and 1972. Because of their age and fuel-type, Units 1 and 2 are far less efficient and more expensive generating units when compared to the marginal generating units in the New England. For example, these units operate on 0.3 percent sulfur heavy fuel oil which has become substantially more expensive, in both relative and absolute terms, in recent times, and face substantial environmental compliance costs to keep up with increasingly strict emission standards in coming years. The heat rates for Norwalk Units 1 and 2 range from approximately 10,000-13,000 BTU/kWh. Similarly, Norwalk's age and technology require approximately sixty full-time employees to operate. In comparison, NRG's Connecticut Jet Power LLC subsidiary

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47 Under the FCM Market Rules, Norwalk's Dynamic De-List Bids could not exceed 80 percent of the $7.50/kW-month CONE used in the First FCA.

operates approximately 176.4 MW of fast-start peaking generation with only two full-time employees.

III. DESCRIPTION OF THE FILING PARTIES' PROPOSAL

The Filing Parties' Proposal revises Market Rule 1 to provide the treatment and compensation for capacity resources whose De-List Bids exceed the market clearing price in an FCA, but are nevertheless rejected because the resources are needed for reliability. A capacity resource whose Permanent De-List Bids are rejected for reliability reasons can choose to receive its De-List Bid or can file to collect its full cost-of-service.[48] Similarly, a resource that has submitted a Non-Price Retirement Request, but agrees not to retire because it is needed for reliability, can either agree to take the FCA clearing price, or may file with the Commission for cost-of-service rates.[49] In contrast, Static De-List Bids that are rejected for reliability reasons will receive only their "net risk adjusted going forward costs", i.e., their mitigated De-List Bid.[50] Likewise, Dynamic De-List Bids that are rejected for reliability reasons will have their compensation capped at their bid price (which cannot exceed 80 percent of CONE).[51] Dynamic De-List Bids are not reviewed by the Market Monitor prior to the FCA, may be challenged before the Commission as part of ISO-NE's filing of the auction results and may be reduced as needed to reflect resources' "net risk adjusted going forward costs."[52]

The Filing Parties assert that compensating capacity resources at their "net risk adjusted going forward costs" is just and reasonable compensation because they represent "the price at or

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48 Filing Parties' Transmittal Letter at 19-20.

49 *Id*. at 21. If the resource must make additional capital expenditures to keep operating, it may make a separate FPA 205 filing to recover those costs. *Id*.

50 *Id*. at 16-19.

51 *Id.* at 19.

52 *Id*. *See* Market Rule 1 § 13.1.2.3.2.1.2.

above which the resource is willing to be obligated to provide services as a capacity resource."[53] The Filing Parties' witness, Mr. Schnitzer, asserts that "a resource should want to provide service at a price that allows [it] to recover its going forward costs and allows it to remain available in the capacity market to earn additional amounts to apply toward its fixed costs, as a return on investment."[54] ISO-NE further justifies this component of the Filing Parties' Proposal on the logic that limiting capacity resources to their "going forward costs" will prevent resources from "toggling between cost-of-service and market rates."[55]

IV. STANDARD OF REVIEW

The FCM Settlement states that "[a] capacity Resource having a Permanent De-list Bid, De-list Bid, or Export Bid that is rejected for reliability reasons shall be paid a just and reasonable price (***as determined by FERC***)."[56] Thus, the FCM Settlement vests the Commission with plenary authority to determine a just and reasonable price that is not in any way circumscribed by the fact that the issue is now being put before the Commission by the Filing Parties pursuant to FPA Section 205. Accordingly, the Filing Parties' assertion that, since this filing is made pursuant to Section 205 of the FPA, the Commission plays only "a passive and reactive role" and "must accept" the Filing Parties' Proposal if it is just and reasonable, even though an intervenor or the Commission may have an alternative proposal that is superior to that of the Filing Parties,[57] is simply incorrect. Moreover, the Commission has made clear that nothing in the FCM Settlement precludes the owner of a resource with a rejected De-List Bid

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53 Filing Parties' Transmittal Letter at 19.

54 *Id.* at 19 (citing Attachment 2 ("Schnitzer Testimony") at 10.

55 *Id*. at 16-17.

56 FCM Settlement, § 11.III.K (emphasis added).

57 *Id*. at 7.

from proposing what it believes is just and reasonable compensation,[58] including the submission of RMR agreements.[59]

V. PROTEST

A. Resources Whose De-List Bids Are Rejected For Reliability Must Have A Reasonable Opportunity To Recover Their Long-Run Costs (Including A Reasonable Rate Of Return).

Under the FPA, public utilities are entitled to rates that permit them to earn a return commensurate with returns earned by firms having similar business and financial risks.[60] The Commission has recognized that, in a competitive market, generators needed for reliability must have a reasonable opportunity to recover their long-run costs, including a reasonable rate of return.[61] The Commission has further recognized that, in order for a generator needed for

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[58] *FCM Market Rules Order* at P 93 (2007) ("Similarly, in response to NRG's comments, we will not address here the issue of what the just and reasonable compensation should be for a resource whose de-list bid is rejected for reliability reasons. Rather, when and if we are presented with a specific case in the future, we will consider the evidence presented and make our decision at that time.").

[59] *Id*. ("While the Settlement Agreement is intended to reduce or eliminate the need for RMR contracts, we agree with PSEG that the Settlement Agreement does not explicitly preclude the owner of a resource from seeking an RMR contract when the resource is needed for reliability and the resource cannot receive adequate compensation through the markets. Consistent with current RMR contract evaluations, when and if an entity seeks an RMR contract under FCM, we will consider the evidence presented in order to determine the need for the contract; in light of ISO-NE's stakeholder process.").

[60] *Bluefield Water Works and Improvement Co. v. Public Service Commission*, 262 U.S. 679, 692-93 (1923) ("*Bluefield*") ("[a] public utility is entitled to such rates as will permit it to earn a return . . . equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.").

[61] *See, e.g., Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697-A, 123 FERC ¶ 61,055 at P 409 (2008) ("When the Commission determines that a seller lacks or has mitigated market power, it is

reliability to have a reasonable opportunity to recover its long-run costs, the market must produce prices that appropriately reflect and compensate the generator for the locational value of the reliability service it is providing.[62] When market design elements are not well coordinated, and the value of resources' local reliability service is not reflected in the market price, reliability compensation issues arise and may preclude some generators from having a reasonable opportunity to recover their long-run costs in the market.[63]

When generators needed for reliability do not have a reasonable opportunity to recover their long-run costs in the market, the resulting rates are necessarily unjust and unreasonable and the Commission has an obligation to provide a remedy.[64] The Commission has held that there is no "one-size-fits-all" solution to address such reliability compensation issues,[65] and that there are many possible market design solutions that must be considered.[66] For the reasons set forth

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making a determination that the resulting rates will be established through competitive forces, not the exercise of market power, and thus will fall within a zone of reasonableness which protects customers against excessive rates, on the one hand, but allows the seller the opportunity to recover costs and earn a reasonable rate of return, on the other hand. This is fully consistent with the fundamental rate principles set forth in *Hope* and *Bluefield*, *supra*, and their progeny."); *Bridgeport Energy*, 113 FERC ¶ 61,311 at P 29 (2005), *order on contested settlement*, 118 FERC ¶ 61,243 at P 60 (2007).

[62] *Devon Power LLC*, 110 FERC ¶ 61,313 at P 20 (2005) (directing ISO-NE to "implement a market-based mechanism…that appropriately values capacity according to location…."); *Devon Power LLC*, 110 FERC ¶ 61,315 at P 50 (2005) ("Once a mechanism that properly values capacity based on its location is finalized and in place, capacity resources will be able to recover their costs and earn consistent reasonable rates of return. . . .").

[63] *PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,112 at P 19 (2004) ("*Reliability Compensation Order*"); *Devon Power LLC,* 103 FERC ¶ 61,082 at P 28 (2003) (finding that high cost, seldom-run units cannot recover costs in Southwest Connecticut because of lack of locational price signals).

[64] *Devon Power Company*, 104 FERC ¶61,123 at P 33 (2003).

[65] *Reliability Compensation Order* at P 15 (2004).

[66] *Id*. at 19 ("Market design features that can work as solutions to these problems include: locational changes such as locational installed capacity, locational operating reserves, locational pricing for energy in times of local operating reserves scarcity; higher bid caps or relaxed mitigation for otherwise mitigated units needed for reliability (increased reference prices; proxy

below, the Filing Parties' Proposal is not just and reasonable because it neither provides a reasonable opportunity for some capacity resources that are needed for reliability to recover their long-run average costs in the market, nor reflects the locational value of the system security reliability service those resources are required to provide.

B. Mitigation Caps Imposed On Static And Dynamic De-List Bids Do Not Reflect Bids That Would Be Submitted In A Competitive Long-Run Market Like The FCM And Are An Unjust, Unreasonable And Confiscatory Basis For Compensating Resources Whose De-List Bids Are Rejected For Reliability.

The Filing Parties' Proposal to compensate those resources at their *as-bid* "net risk adjusted going forward costs" is unjust and unreasonable because the mitigation limits imposed on the De-List Bids do not reflect the bids that would be submitted in a competitive, long-run market as set forth below.

1. The FCM is a long-term market for which sound economic principles require compensation at long-run average costs – not short-run marginal costs.

As a starting point, the Filing Parties fail to take into account that the FCM is a long-term market. The three-year advanced Commitment Period is intended to "provide a planning period for new entry, so that potential new capacity resources can participate in the auction and compete with incumbent resources."[67] In economic terms, the three-year planning period increases the elasticity of the short-term supply curve into a more elastic long-term supply curve because suppliers of capacity resources can respond to price movements by changing the amount of capacity they offer in the auction.[68]

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unit based approaches; increased offer caps in unit-based cost capping regimes); or other approaches.").

67 FCM Settlement at 27.

68 *Id.* at 28. *See also FCM Market Rules Order* at P 5.

Despite the fact that the FCM operates as a long-term market where entry is expected to provide price discipline, compromises reached in the FCM Settlement imposed significant limitations on the ability of existing generation to freely bid in the FCA. In particular, all existing capacity resources are required to participate in the FCA as price-takers unless they choose to de-list their resource(s).[69] Static and Dynamic De-List Bids are effectively capped at a resource's short-run marginal costs or 80 percent of CONE.

As Dr. Jonathan A. Lesser and Dr. David W. DeRamus explain in their affidavit, the fundamental flaw in the Filing Parties' Proposal to pay the "as-bid" price to resources with rejected Static or Dynamic De-List Bids is that those bids, prescribed by the Market Rules to include only "net risk adjusted going forward costs," are completely at odds with economic theory which recognizes that suppliers in a workably competitive long-term market, like the FCM, will bid their long-run average costs.[70] Indeed, in the absence of monopsonistic behavior,[71] new entry is presumed to bid its long-run average costs. Simply put, then, in a long-term market where there can be new entry, resources whose bids are rejected for reliability reasons should be compensated based on their own long-run average costs or the cost of new

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69 FCM Settlement at § 11, Part IV.A1.

70 Lesser-DeRamus Affidavit at 10:5-7 (citing A. Kahn, *The Economics of Regulation: Principles and Institutions*, at 70-74 (Cambridge, MA: MIT Press 1988)).

71 Monopsonistic behavior is a problem with the FCM as it is currently structured. While the FCM rules provide for the Market Monitor to review FCA bids for new capacity from net buyers of capacity when those bids are less than 75 percent of the CONE, FCM rules do not effectively prevent monopsonistic market power by ***requiring*** that all new entry bid its long-run average costs. Thus the mitigation rules governing existing resources and new entry are unbalanced and distort the FCA market clearing prices. *See* Motion To Intervene And Comments Of The New England Power Generators Association, Inc., Docket No. ER08-633-000, at 3 (Apr. 17, 2008) ("However, substantial amounts of new capacity entered the market with no price sensitivity, as a result of new capacity resources electing to be treated as existing resources. These new resources shifted the clearing price down by becoming 'price takers,' as opposed to submitting bids that reflected that resource's actual long-run costs, and thereby had the unintended effect of undermining the method for determining the actual cost of new entry through the auction.").

entry.[72] Accordingly, the Filing Parties' Proposal is flatly inconsistent with sound economic principles governing long-term markets.[73]

2. The Filing Parties' Proposal to compensate resources based on bids that were involuntarily mitigated to their short-run marginal costs in a long-term market is contrary to economic theory.

The Filing Parties erroneously rely on highly simplified models of economic theory to justify compensating resources whose Static and Dynamic De-List Bids are rejected for reliability based on their short-run marginal costs, i.e., "net risk adjusted going forward costs."[74] The Filing Parties' assertions that resources should "willingly" operate if they are able to recover their short-run marginal costs,[75] as found in the testimony of Mr. LaPlante and Mr. Schnitzer,[76] is based on a fundamental misconception about bidder behavior in market auctions and is founded on undue reliance on highly simplified models of economic theory that do not take into account the fact that participants will need to recover at least their long-run average cost in the long run.

In a perfectly competitive short-term market with an infinite number of sellers and buyers, none of whom are sufficiently large to affect market clearing prices through their bids or

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72 Lesser-DeRamus Affidavit at 10:9-12.

73 Lesser-DeRamus Affidavit at 10:12-13.

74 *See supra*, note 4.

75 NSTAR also asserts in a single sentence that "[b]asic economic principles indicate that a supplier will remain in the market without economic disadvantage if it recovers its short-run marginal cost," without any explanation or citation to authority to support its assertion. *See* Motion to Intervene, Comments and Protest of NSTAR Electric Company, Docket No. ER08-1209-000, at 5 (Jul. 22, 2008) ("NSTAR Comments").

76 Filing Parties' Transmittal Letter, Attachment 1 ("LaPlante Testimony") at 23:9-11 ("However, like a Static De-List Bid, a Dynamic De-List Bid represents the price at or above which the resource is willing to be obligated to provide service as a capacity resource. That price should coincide with a unit's going forward costs because, as Mr. Schnitzer describes, a resource that wishes to remain in the capacity market over the long term would want to provide service at a price that covers its going forward costs."); Schnitzer Testimony at 10:12-15 ("A resource submitting a one-year de-list id should be able and willing to remain available for that year if it (a) is ensured that it will at least recover its going forward costs for the year, and (b) maintains its opportunity to participate in the market in future years.").

offers, each seller can be expected to offer a product at a price just equal to its marginal cost of production.[77] By the same token, however, each buyer can be expected to purchase the product at a price just equal to the marginal value it places on the product.[78] This hypothetical model of perfect competition in a short-term market, even if it did exist, does not, of course, describe conditions in a long-term market such as the FCM. In such long-term markets, suppliers will not submit bids at their short-run marginal costs. Bidding above short-run marginal costs is an inevitable and necessary consequence of suppliers' need to maximize their ability to earn a return that will fairly compensate investors for the financial risk to their capital in all real-world markets, including markets that are workably competitive.[79] This expectation is also consistent with empirical observation in many power markets.[80]

A market rule that compensates resources needed for reliability based on their short-run marginal costs – in a long-run market such as the FCM – is not only economically unrealistic, but it also sends the wrong price signals.[81] Compensating units needed for reliability at only

[77] Lesser-DeRamus Affidavit at 13:3-6.

[78] Lesser-DeRamus Affidavit at 13:6-8.

[79] Lesser-DeRamus Affidavit at 14:8-12 (citing Paul D. Klemperer & Margaret A. Meyer, "Supply function Equilibria in Oligopoly under Uncertainty," 57 *Econometrica*, 1243-1278 (1989); Lawrence M. Ausubel and Peter Cramton, "Demand Reduction and Inefficiency in Multi-Unit Auctions," (University of Maryland, Working Paper, 2002); Peter Cramton, "Competitive Bidding Behavior in Uniform-Price Auction Markets," *Proceedings of the Hawaii International Conference on System Sciences* (January 2004).

[80] Lesser-DeRamus Affidavit at 14:12-15:4 (citing James Bushnell and Celeste Saravia, "An Empirical Assessment of the Competitiveness of the New England Electricity Market," (UC Berkeley, Working Paper, CSEM-101, 2002); Erin T. Mansur, "Pricing Behavior in the Initial Summer of the Restructured PJM Wholesale Electricity Market," (UC Berkeley, POWER Working Paper-083, 2001); Bradley Krantz, Robert Pike & Eric Hirst, "Integrated Electricity Markets in New York: Day-ahead and Real-time Markets for Energy, Ancillary Services, and Transmission," New York ISO (2002); N., N. von der Fehr Fabra, and D. Harbord, "Designing Electricity Auctions," *RAND Journal of Economics*, 37(1):23-46 (2006); R. Sioshansi & S. Oren, "How Good are Supply Function Equilibrium Models: An Empirical Analysis of the ERCOT Balancing Market," *Journal of Regulatory Economics*, Vol. 31, No 1, pp 1-35, (Feb. 2007)).

[81] Lesser-DeRamus Affidavit at 15:5-11.

their short-run marginal costs undercuts the long-run price signal to develop transmission solutions or new capacity (from either supply or demand resources) to resolve the reliability violations and, instead, subsidizes the failure to properly plan and construct the transmission system to prevent such reliability problems. Given the three-year planning period under FCM, there are no sound economic reasons why resources with rejected De-List Bids should be required to provide such subsidies.

There is also no support for the Filing Parties' assumption that existing resources who submitted Static and Dynamic De-List Bids in the first FCA necessarily were *willing* to operate at their short-run marginal costs if their bids were rejected. Resources (such as Norwalk) who submitted Dynamic De-List Bids well above the expected market clearing price did so because they were *prohibited* from bidding their long-run average costs and fully expected that, in the unlikely event that their De-List Bid was rejected, they would be compensated at a just and reasonable rate as the FCM Settlement requires, i.e., at their long-run average costs.

To be clear, the question here is not whether mitigating the Static or Dynamic De-List bids of all resources in a single clearing price auction to their short-run marginal costs is appropriate from a market mitigation perspective. Rather, the issue is whether it is just, reasonable and non-confiscatory to then pay a single resource only its mitigated De-List bid (i.e., short-run marginal costs) when it is determined, outside of the auction's mechanics, that the resource is needed to address local reliability violations unrelated to the purpose of the auction for which the mitigated bid was submitted (*i.e.* on a "pay-as-bid" basis). The answer is clearly "no." While a resource may voluntarily choose to bid its short-run marginal costs in a uniform price auction where it expects to be selected and then receive a clearing price that will provide it with inframarginal revenues, a generator in an as-bid market will bid at what it estimates the market clearing price to be.[82] It would simply be economically irrational for a generator in an as-bid market to offer to sell at less than what it believes is the market clearing price.[83] Thus, a resource that does not expect to be able to earn inframarginal revenues in the energy and ancillary services markets, and knows it will be paid its "as-offered" bid would not bid its short-run marginal costs. Instead, it would bid the higher of the expected cost of new entry or its long-run average costs.

In such circumstances, and where the resource with a rejected De-List Bid does not otherwise have a reasonable opportunity to earn inframarginal energy revenues and recover its long-run average costs in the markets, the Commission must either provide: (1) a mechanism for determining a market-based price for the reliability service the resource is being compelled to provide (e.g., the NRG Proposal); or (2) pay the resource its cost-of-service.[84] The Commission cannot, however, simply compel the resource to operate for reliability at a rate based on the involuntarily mitigated, rejected De-List Bid where the resource was never given the opportunity to bid the cost of providing that local reliability service and where the Commission never made a finding that the mitigated De-List Bid is just and reasonable compensation for providing that local reliability service on a "pay-as-bid" basis.[85]

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82 Lesser-DeRamus Affidavit at 17:14-18. *See also infra* at note 88.

83 Lesser-DeRamus Affidavit at 17:18-18:2.

84 *See Devon V*, 107 FERC ¶ 61,240, at PP 44-45 (finding that a market design solution would provide a reasonable solution to the reliability compensation issues in SWCT, but holding that the Commission will continue to use RMR contracts for units that are needed for reliability but cannot earn sufficient revenues from the markets to continue operation).

85 *See Edison Mission Energy, Inc. v. FERC*, 394 F.3d 964, 968-69 (D.C. Cir. 2005) (vacating the Commission's orders approving NYISO's use of automated mitigation procedures ("AMP") because the Commission failed to "articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made,'" *citing Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ns. Co.*, 463 U.S. 29, 43 (1982), and giving no reason to suppose that application of AMP would not wreak substantial harm by "curtailing price increments attributable to genuine scarcity that could be cured only by attracting new sources of supply.").

Finally, the Filing Parties' reliance on the Commission's recent order accepting the New York Independent System Operator's ("NYISO") proposal to strengthen market power mitigation for the New York In-City ICAP Market for the proposition that rates in a competitive market based on going forward costs are just and reasonable is inapposite.[86] First, the NYISO In-City ICAP Market is a short-term, monthly capacity market and so the *NYISO In-City Order* is simply not relevant to a long-term, forward market like FCM. Second, the Commission was approving the use of short-run marginal cost-based offers to calculate mitigation reference prices to be used in a single clearing price auction – not as a form of as-bid compensation. Third, the cases cited by the Commission in the *NYISO In-City Order* for the proposition that "it is just and reasonable to base competitive offer prices on marginal costs," do not stand for that proposition.[87] Instead, each of them stands only for the proposition that it is just and reasonable to set prices using a single market-clearing price auction, which is designed to *encourage* the submission of bids at marginal costs.[88] They do ***not*** stand for the proposition that it is

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86 Filing Parties' Transmittal Letter at 4 (citing *New York Indep. Transmission Sys. Operator, Inc.*, 122 FERC¶ 61,211 at P 36 (2008) ("*NYISO In-City Order*").

87 *Id*. at n.31 (citing *Commonwealth Edison Co.*, 113 FERC ¶ 61,278 (2005), *citing to New York Indep. Sys. Operator, Inc., order on reh'g,* 110 FERC ¶ 61,244 (2005); *PJM Interconnection, LLC,* 117 FERC ¶ 61,331 (2006)).

88 *Commonwealth Edison Co.*, 113 FERC at P 43 n.21 ([T]he "single clearing price" method and has the benefit of encouraging all sellers to place bids that reflect their actual marginal opportunity costs. This method is in contrast to the "pay as bid" method, where each bidder is paid only what it bids. Under the pay as bid method is that each bidder is encouraged to bid the highest price it believes will be accepted in the auction, because it will only be paid as much as it bids. *** The single price method has been proposed and found to produce just and reasonable rates for all the energy and ancillary service markets currently operated by the independent system operators and regional transmission organizations under our jurisdiction.") (citing to *New York Indep. Sys. Operator, Inc*., 110 FERC ¶ 61,244 n.76 (2005) ("For example, NYISO pays generators the market clearing price (rather than their as-bid price), because, under this model, the generator has the proper incentive to bid the lowest price that covers its marginal cost, knowing that if the market produces a higher price it will receive the market price. If generators were paid only the price they bid, they would then try to guess at the market clearing price or else they would never receive more than their bid. Clearly, if suppliers know that they are going to receive only what they bid, they will attempt to bid the market clearing price, a

appropriate to use mitigated bids based on short-run marginal costs to "pay as bid" resources that do not clear in the auction – and, in fact, stand for the exact opposite proposition.

Accordingly, the Filing Parties' Proposal to pay generators the bids they offer in a single clearing price auction on an as-bid basis is unreasonable and does not reflect the outcomes expected in workably long-run competitive market.

3. The Filing Parties' Proposal will not provide older, high cost low capacity factor resources with a reasonable opportunity to recover their long-run average costs from ISO-NE's markets when their De-List Bids are rejected for reliability.

The results of the first FCA demonstrate that capacity resources with rejected De-List Bids are typically going to be those with high operating costs and low capacity factors (like NRG's Norwalk Units 1 and 2) and, as a result, these units will earn little or no inframarginal revenues in the energy market. Consequently, the Filing Parties' Proposal to compensate resources with rejected Static or Dynamic De-List Bids at only their short-run marginal costs will not provide those types of resources with a reasonable opportunity to recover their long-run average costs, including a return of and on capital, from the ISO-NE markets in the long run.

4. The Filing Parties' Proposal does not compensate resources for the option value to ISO-NE and consumers of being able to reject their De-List Bids for local reliability.

In their testimony, Mr. LaPlante and Mr. Schnitzer erroneously characterize submission of Static and Dynamic De-List Bids as purchasing an "option" to stay in the capacity market,

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practice that introduces additional risks into the market.")) (internal citations omitted); *PJM Interconnection, LLC,* 117 FERC ¶ 61,331 at P 141 n.101 (2006) ("The Commission has previously found single clearing price markets to be just and reasonable, and New Jersey Rate Counsel has made no showing as to why the use of a single clearing price here would be unjust and unreasonable.") (*citing Commonwealth Edison Co., and New York Indep. Sys. Operator, Inc., supra*).

rather than to permanently de-list.[89] Their characterization is incorrect, because a generator is *compelled* to participate in the FCM, cannot de-list without an ISO-NE finding that it is not needed for reliability and is forbidden from submitting a bid reflecting its actual cost to provide reliability service. Instead, the resource's bid is mitigated to the higher of 80 percent of CONE or its resource's short-run marginal costs,[90] even though there is no finding that the individual resource has market power in a particular FCA.

In a competitive long-run market, resources have the freedom to enter and exit the market and submit competitive bids. However, existing resources in the FCM are precluded from voluntarily leaving the market when they are needed for local reliability, and are prohibited from submitting competitive bids that reflect their cost of providing the reliability service. This is because resources who wish to leave must submit De-List Bids which, if those resources are needed for local system security, will be rejected – even though the resources are not needed to satisfy ICR, and their De-List Bids cannot set the FCM clearing price. In short, the FCM Market Rules dispense with an essential element of a competitive market in order to give ISO-NE an

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89 LaPlante Testimony at 15:8-11 ("[i]f the resource believed that the value of the option to stay in the market in future years exceeded the cost of maintaining that option for one year, it would submit a one-year de-list bid."); Schnitzer Testimony at 6:1-3 ("Temporary de-list bids indicate that the resource has chosen to retain the option of staying in the capacity market long term, but not to participate for one year if the FCM price is below the de-list bid level.").

90 NSTAR asserts that "Constitutional law recognizes that federal regulation may require an energy supplier to continue to provide service but may limit its compensation to its out-of-pocket cost." NSTAR Comments at 5 (citing *Pennzoil v. FERC*, 439 U.S. 508 (1979) ("*Pennzoil*")). The *Pennzoil* case stands for no such proposition and is wholly inapposite to the issue before the Commission in this proceeding. The issue in *Pennzoil* involved the authority of the Commission to give special relief from applicable area and nationwide rates to individual producers of natural gas because of escalating royalty costs that were a function of the unregulated market price for natural gas. *Id*. at 517. The Commission was not compelling the individual natural gas producers to produce when they did not want to, nor were the individual natural gas producers being required to provide another service (e.g., local reliability service) different from other producers with appropriate compensation.

option to call on any resource that it needs for system security reliability and prevent it from exiting the market.

This option to prevent generators from leaving the market clearly has value to ISO-NE, and indirectly to the customers who use or rely on the ISO-operated transmission system. That value is substantially more than the short-run marginal costs of the resource whose De-List Bid is rejected. The value of that option is, as previously discussed, equal to the lower of the cost of replacing the resource or the expected cost of an outage if the resource were not available to maintain system security. Thus, the Filing Parties' Proposal is unjust and unreasonable because it does not compensate resources with rejected Static and Dynamic De-List Bids for the value of the system security reliability service it provides.

The combination of existing FCM Market Rules and the Filing Parties' Proposal would force such resources to choose between submitting Static or Dynamic De-List Bids, for which compensation is limited to their short-run marginal costs, and Permanent De-List Bids, that entitle them to full cost-of-service but preclude them from further participation in the FCM. The imposition of such a "Hobson's Choice"[91] is unjust and unreasonable for all the reasons previously discussed, i.e., the FCM does not appropriately compensate resources for the locational value of their capacity to system security and limitations on Static and Dynamic De-List Bids do not reflect rational economic behavior in a long-term market.

Until ISO-NE's Market Rules are revised to directly address the need for market-based compensation for system security,[92] resources should not be required to choose between Static and Dynamic De-List Bids that do no allow just and reasonable compensation for the system

[91] The phrase "Hobson's Choice" refers to an illusion of having a choice and reportedly comes from Thomas Hobson (1544?–1630), an English keeper of a livery stable, who reportedly gave customers the "choice" to take either the horse nearest the stable door or none at all.

[92] *See FCA Order* at P 36 ("parties are encouraged to address concerns related to the determination of capacity zones [based on ISO-NE's use of the more stringent TSA").

security reliability service they are compelled to provide, and Permanent De-List Bids that provide access to full cost-of-service compensation, but foreclose those resources' ability to receive FCM capacity payments in the future when they are no longer needed for reliability. Otherwise, resources are being forced to make long-term decisions without a comprehensive long-term reliability compensation structure in place (i.e., one that compensates both resource adequacy and system security). Moreover, providing different levels of compensation for the same reliability service based on the period for which the resource wants to de-list is unduly discriminatory and violates FPA Section 205.

Finally, adopting the Filing Parties' Proposal for different compensation schemes based on the artificial distinction between Permanent De-List Bids and Static/Dynamic De-List Bids may also result in higher costs to consumers because a resource that has no likely opportunity to recover its long-run average costs in the market may be effectively forced to exit the FCM on a permanent basis. Norwalk, for example, may be forced to submit a Permanent De-List Bid. If that resource is needed for system security, it may be many years (at least three) before the resource is allowed to de-list. By that time, market conditions may be such that the resource has an opportunity to recover its costs, but is forced to deactivate or retire because it is ineligible for capacity payments due to its permanent de-listing. This may result in higher costs to consumers if the cost to replace the permanently de-listed resource is higher than its long-run average costs.

Compensating resources with rejected Static and Dynamic De-List Bids at rates that reflect a competitive long-run market outcome, while allowing them to remain in the FCM once they are no longer needed for reliability, does not constitute "toggling" between market rates and cost-of-service rates. Rather, it constitutes providing such resources with a reasonable opportunity to recover their long-run average costs by providing market-based rate compensation for all the reliability service they provide to the system, not just resource adequacy.

5. The ISO-NE Tariff formula for calculating "net risk adjusted going forward costs" is inherently flawed and does not provide an accurate measure of either true going forward costs or short-run marginal costs.

For all the reasons previously discussed, the Filing Parties' Proposal to compensate rejected Static and Dynamic De-List Bids at anything less than their long-run average costs is not based on sound economic principles. However, setting aside the flawed economic theory underpinning the Filing Parties' Proposal, the formula used by ISO-NE to calculate "net risk adjusted going forward costs" is patently unjust and unreasonable because it will not provide those resources that are unable to earn meaningful inframarginal revenues in the energy and ancillary services markets (like Norwalk Units 1 and 2) with sufficient compensation to continue in operation. The Commission has consistently recognized that resources needed for reliability must at least be paid those costs necessary for them to remain available.[93]

Under Market Rule 1, generators who submit Static De-List Bids above 80 percent of CONE must demonstrate that the bids are consistent with their "net risk adjusted going forward costs," and Dynamic De-List Bids may only be submitted when the price in the descending clock FCA drops below 80 percent of CONE. Under the Filing Parties' Proposal, rejected Static De-List Bids would be paid as bid and rejected Dynamic De-List Bids could be challenged and mitigated down to their "net risk adjusted going forward costs."[94] Under ISO-NE's Tariff, "net risk adjusted going forward costs" are determined by: (1) adjusting a generator's historic short-run variable O&M expenses by the expected forced outage rate; (2) adding a risk factor based on

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93 *See, e.g.*, *Pittsfield Generating Co., L.P.*, 115 FERC ¶ 61,059 at P 66 (2006) ("Providing only minimum, marginal, and variable cost recovery may not allow an RMR unit to maintain the facility so that it can continue to operate reliably."); *PSEG Power Connecticut, LLC*, 110 FERC ¶ 61,441 at P 21 (2005) ("providing only minimum, marginal and variable cost recovery to the Power Connecticut units may not allow them to be maintained in such a manner that they can continue to operate reliably, defeating the purpose of the contracts to ensure that the units are 'available' to support reliability.").

94 Filing Parties' Transmittal Letter at 19.

the probability the unit would suffer a forced outage and need to purchase replacement capacity; and (3) subtracting the difference between historical IMR from energy and ancillary services markets, and ISO-NE's estimate of peak energy rents for the hypothetical peaking unit used to establish CONE.[95]

The formula in the ISO-NE Tariff for calculating "net risk adjusted going forward costs" excludes altogether many expenses which generators must pay to remain in business. For example, it excludes property taxes, insurance and a substantial portion of a resource's full labor costs. However, a generator cannot stop paying property tax payments, is required by law to maintain adequate insurance coverage and cannot, for example, release all plant personnel and expect to rehire them one year later. A generator will also incur additional costs in the form of "wear and tear" on the facility, hastening the need for capital additions that would not otherwise occur during the proposed de-list year, *but for* the requirement for the unit to operate and provide reliability service. However, capital costs and expenses associated with major repairs to restore decreases in capacity, or to maintain compliance with the resource's operating permit are classified as "opportunity costs" and are not included in ISO-NE's "net risk adjusted going forward costs" formula.[96]

In addition, the formula does *not* compensate generators for return of or return on capital and, in fact, explicitly states that debt costs cannot be included.[97] Prohibiting generators from recovering a return leaves them with no avenue to offset the costs associated with the significant business and financial risks on resources and their creditors.[98] These risks result from the

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[95] Lesser-DeRamus Affidavit at 21:18-22:13 (citing Market Rule 1 at Market Rule 1 at § 13.1.2.3.2.1.1).

[96] ISO-NE *De-List Data Submittals Guideline* ("*De-List Guide*") at 7. The *De-List Guide* is attached as Exhibit No. NRG-4.

[97] Market Rule 1 at § 13.1.2.3.2.1.2.

[98] Lesser-DeRamus Affidavit at 23:12-24:3.

resource's obligation to operate the resource, offer energy into the day ahead and real time energy markets and maintain the resource for the benefit of New England ratepayers, and carry monetary consequences not compensated by the "net risk adjusted going forward cost" formula.[99] For example, these business risks include the potential that a reliability resource committed in the day-ahead energy market will incur substantial real-time replacement power costs due to a forced outage beyond its control,[100] or that the forced outage will occur during so-called "shortage hours" and result in decreased FCM capacity payments.[101] Business risks also include the cost of compliance with new laws and regulations enacted long after the De-List Bid was submitted. As an example, resources in Connecticut are facing substantial new environmental regulations.[102] Generation resources must also comply, for example, with NERC, NPCC, and OSHA standards and will inevitably incur costs in doing so. The inability to earn a return to offset the costs associated with these risks, and the failure to include them in ISO-NE's

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99 *See* South Carolina Gas and Electric Company's Response To Deficiency Letter, Docket Nos. ER07-423-000, *et al*., at 1 (Mar 12, 2007) ("SCE&G Response") ("To illustrate, if SCE&G were to engage an independent contractor to operate SCE&G's own facilities under a good utility practice standard, that independent contractor would face business risks; and the mere recovery of out of pocket O&M costs would not compensate that contractor for those business risks. Reversing the roles, and making SCE&G the contractor for facilities used for New Horizon, places on SCE&G the exact same business risks. Operating these facilities under a required standard of care - whether that standard is negligence or good utility practice or something else -- creates the risk with potential financial consequences. By operating and maintaining these facilities, SCE&G faces a financial impact if there were a breach of the duty of care which triggered compensation for damage or injury and/or regulatory sanction.").

100 Lesser-DeRamus Affidavit at 24:3-10.

101 FCM Settlement, Explanatory Statement at 11 ("The Settlement Agreement provides for loss of capacity compensation for capacity resources that fail to perform (subject to certain well-defined excuses) during these Shortage Events. On any critical day, a resource can have their compensation reduced up to 10% of annual FCA Payment if it is not available and, in any month, a resource can lose up to two and one-half months of its annual FCA Payment.").

102 *See, e.g.,* Direct Testimony of Cynthia L. Karlic on behalf of Norwalk Power, LLC, Exhibit No. NRG-12, filed in Docket No. ER07-799-000, et al., (Apr. 27, 2007) (describing anticipated environmental compliance expenditures that Norwalk expects to have to incur in order to continue to operate).

so-called "net risk adjusted going forward costs," can and will result in some reliability resources not recovering their fixed costs and having to shut down. The costs associated with these risks, for the most part, could be avoided by de-listing and are significantly higher for resources being forced to accept a year-long commitment to operate three years hence, as compared to a resource in a short-term market that is being required to operate the next hour or next day. The Commission has recognized that requiring public utilities to assume these types of risks without a commensurate return is unjust and unreasonable and approved the inclusion of management fees to cover those risks.[103]

Furthermore, not compensating generators for return of or on capital will signal bondholders that, three years hence, the generator's revenues will not include any allowance for debt service and this obviously raises the risk that a generator will violate its bond covenants.[104] The result may be that bondholders will call the bonds immediately, precipitating a financial crisis that forces the generator into bankruptcy.[105] Such an outcome could also send a signal to potential future market entrants, who will eventually be treated as existing generators, that the risks of capacity investment in ISO-NE are significant, thereby reducing incentives for new entry and aggravating future capacity shortages and reliability constraints.[106] As a result, ISO-NE's formula does not produce a reasonable measure of the going forward costs which generators will actually face, nor does it approximate the costs that appropriately would be considered in a competitive offer price for a service to be provided for a one-year term three to four years in the

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[103] *South Carolina Electric & Gas Company*, Docket No. ER07-423-000 (Apr. 20, 2007) (letter order approving facilities agreement); *High Island Offshore System, L.L.C.*, 110 FERC ¶ 61,043, *reh'g* 112 FERC ¶ 6,0150 (2005); *Tarpon Transmission Co.*, 57 FERC ¶ 61,371 (1991).

[104] Lesser-DeRamus Affidavit at 26:1-4.

[105] *Id*. at 26:4-5.

[106] *Id*. at 26:5-9.

future, nor is it likely to attract an amount of capacity (supply and demand resources) into the market that would be commensurate with accurate market price signals.

Moreover, the formula does not even provide an accurate measure of the short-run marginal costs the resource is likely to incur during the Commitment Period three years in the future. For example, the calculation of IMR, which is equal to the difference between ISO-NE's estimate of a resource's variable O&M expenses (including fuel) and the market clearing price, can vary greatly from year to year making it unlikely that historical IMR data used to construct the Static De-List Bid or mitigate a Dynamic De-List Bid will bear any relationship to the IMR earned during the Commitment Period three years hence.[107] This is particularly true for resources like Norwalk whose historical revenues reflect PUSH bidding. Under PUSH, Norwalk was permitted to submit bids which reflected its filed cost of service (with certain modifications) per MWh of its low load factor output. PUSH has now been eliminated and the margins earned under PUSH far exceed a reasonable estimate of future IMR for Norwalk.[108] Finally, the inflation adjustment in the FCM Market Rules places significant risk on the resource because of the three year lag between the calculation and the Commitment Period. By comparison, PJM Interconnection L.L.C.'s offer cap calculation uses an adjusted ten-year historic average inflation index that is less likely to understate the impact of inflation on costs three years hence.[109]

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107 *Id*. at 26:13-17.

108 *See ISO New England Inc. and New England Power Pool*, 118 FERC ¶ 61,018 (2007) (accepting ISO-NE's tariff filing to terminate PUSH bidding effective June 2007).

109 Lesser-DeRamus Affidavit at 28:2-5.

C. The Filing Parties' Proposal Is Not Just And Reasonable, And Is Confiscatory, Because It Does Not Appropriately Compensate For The Locational Value Of The Local Reliability Service Which Resources With Rejected De-List Bids Are Compelled To Provide.

1. The FCM is not designed to procure and compensate capacity resources for system security and other local reliability requirements used to reject De-List Bids.

Setting aside the failure to compensate resources in a manner consistent with a long-run forward market, the Filing Parties' Proposal fails to compensate resources for the locational value of the local reliability service they are compelled to provide and which the FCM is not intended to procure or compensate. Generally speaking, reliability has two principal elements: (1) resource adequacy; and (2) system security; and both elements must be met to ensure reliability.[110] Resource adequacy "represents the ability of the system to meet the aggregate power and energy requirement of all consumers" up to an accepted loss of load probability, whereas system security is "the ability of the system to withstand disturbances,"[111] based on a deterministic or narrower set of probabilities. The FCM is designed and intended to procure a level of installed capacity, referred to as the Installed Capacity Requirement ("ICR"), such that the probability of disconnecting non-interruptible customers due to resource deficiency will be no more than one day in ten years, on average (called the "Loss of Load Expectation" or "LOLE").[112] In circumstances where transmission constraints limit the amount of energy that can flow into subregions, ISO-NE uses a Local Sourcing Requirement ("LSR") Standard to ensure that the FCA procures the minimum amount of capacity that must be electrically located

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110 *ISO New England Inc.*, 123 FERC ¶ 61,290 at P 26 (2008 ("*FCA Order*") (citing NPCC Document A-07).

111 *Id*. *See also* "Ensuring Generation Adequacy in Competitive Electricity Markets," Shmuel S. Oren, University of California at Berkeley, working paper at 2, revised June 3, 2003 (http://www.ieor.berkeley.edu/~oren/workingp/adequacy.pdf).

112 *Id*. at P 8 n.19.

within an import-constrained Load Zone to satisfy the LOLE requirement for that subregion.[113] Both ICR and LSR are resource adequacy measures.[114] Thus, the quantity of capacity procured in the FCA, and the resulting clearing price, are driven by an administratively-determined demand that is based on ICR and LSRs.

However, in determining whether to reject a resource's De-List Bid for reliability in the first FCA, ISO-NE also employed a Transmission Security Analysis ("TSA") to determine whether the resource is needed to provide system security.[115] The TSA uses a deterministic analysis to assess the amount of capacity necessary to allow the system to withstand the loss of the largest unit or the loss of the second most critical transmission element after accounting for the occurrence of the first most critical contingency.[116]

The reliability requirements established by the TSA are different, and likely to be much more stringent than ICR and LSRs and, in the first FCA, were the reason that the Norwalk De-List Bids were rejected, even though the resources submitting the De-List Bids were not needed to meet the ICR or LSR.[117] Moreover, the FCM Market Rules allow ISO-NE to reject a De-List Bid for violation of any North American Electric Reliability Corporation ("NERC") or Northeast Power Coordinating Council ("NPCC") reliability standard.[118] Consequently, in future FCAs, it is possible that a resource's De-List Bid could be rejected because of the need for other discrete reliability services such as voltage support, stability, or even load-following within a defined

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113 *Id*.

114 *Id*. at 27.

115 *Id*. at 19. *See also* ISO New England Inc. Forward Capacity Auction Results Filing, Docket No. ER08-633-000, Attachment C (Testimony of Stephen J. Rourke) at 5:15-6:14 (Mar. 3, 2008) ("Rourke Testimony").

116 Rourke Testimony at 5:26-6:3.

117 *Id*. at 7:1-12.

118 Market Rule 1 at § 13.2.5.2.5.

sub-region. As a result, there is a fundamental disconnect between the resource adequacy reliability service and amount of capacity that the FCA is designed to procure, and the other types of reliability service and amounts of capacity that the ISO-NE system needs in certain locations to ensure reliable operation.[119]

2. Neither the FCA clearing price nor resources' rejected De-List Bids appropriately reflect or compensate for the locational value of the local system security and reliability such resources are compelled to provide.

As a consequence of the aforementioned disconnect between the resource adequacy underpinnings of the FCA and local security requirements, neither the FCA clearing price nor the resource's Static or Dynamic De-List Bids appropriately compensate the resource for the locational value of the system security reliability service that it is forced to supply because its Static or Dynamic De-List Bid is rejected.[120] The FCA clearing price does not appropriately compensate the locational value of the resource because it is not based on the intersection of the demand for system security in a particular location and supply offers from new capacity resources (including transmission upgrades) that are capable of providing that system security. In fact, the first FCA had no price separation and reflects no locational value of any kind.[121]

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[119] Motion For Leave To Answer And Answer Of The NRG Companies, Docket No. ER08-633-000, at 11 (May 2, 2008) ("NRG May 2 Answer") ("The NRG Companies do not disagree that there is a disconnect between the detailed methodology for establishing LSR and capacity zones that is specified in Market Rule 1, on the one hand, and the reliability analysis applied to de-list bids, on the other hand, and, as discussed below, generally agree that a properly-functioning FCM should minimize, if not eliminate, reliance on out-of-market solutions.").

[120] This Protest is not a collateral attack the Commission's determination that ISO-NE properly relied on transmission system security requirements to reject De-List Bids in the first FCA. *See FCA Order* at P 27. Instead, the Protest demonstrates that the design of the FCM market is such that neither the FCA clearing price nor the mitigation caps placed on Static and Dynamic De-List Bids compensate resources for the locational value of the system security.

[121] Because the First FCA stopped at the $4.50/kW-month floor while the amount of cleared capacity was still in excess of ICR, the actual price per cleared MW of capacity fell below the floor. FCM market rules ordinarily would that allow resources to reduce (or prorate) the amount of capacity they offered until the quantity/price equals $4.50/kW-month. Ironically, because

Likewise, compensating a resource at its "net risk adjusted going forward costs" is not just and reasonable because De-List Bids based on those costs do not allow the resource to reflect the locational value of the system security reliability service it is being called upon to provide, and the FCA market clearing price does not reflect the locational value of that local system security reliability service. Simply put, a resource that expected the FCA to clear at a price that reflects a system-wide surplus of capacity based on ICR would not submit a De-List Bid based on its "net risk adjusted going forward costs." In such circumstances, the resource would submit a bid that, in conjunction with its expected energy and ancillary market revenues, would at least enable it to recover its long-run average costs.[122] This is particularly likely to be true in the case of older high-cost, low capacity factor units that have no prospects for earning inframarginal revenues in the energy or ancillary services markets and must justify their continued operation to investors based on their ability to earn revenues in the capacity market.

Indeed, the results of the first FCA demonstrate empirically that capacity resources with rejected De-List Bids are typically going to be those with high operating costs and low capacity factors, like NRG's Norwalk Units 1 and 2, that are unable to recover their long-run average costs in the market because they earn little or no inframarginal revenues in the energy market and have fixed and variable costs that may exceed the cost of new entry. Norwalk's annual fixed revenue requirement, as documented in the record pending before the Commission, is $37,664,400 per year for the combined 336 MW output of Norwalk Units 1 and 2, or $9.34/kW-

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Connecticut resources are needed to satisfy system security requirements identified by the TSA, the Commission has found that the ISO-NE Tariff does not allow them to take advantage of such proration. *FCA Order* at PP 74-75. As a result, not only does the FCA clearing price not reflect the locational value of system security, but resources in Connecticut providing such system security reliability service will actually be paid ***less*** than resources outside of Connecticut that are not needed for system security reliability.

[122] Lesser-DeRamus Affidavit at 10:5-12.

month.[123] The recent Integrated Resources Plan for Connecticut, prepared at the direction of the Connecticut Light and Power Company and the United Illuminating Company, found that Norwalk's fixed operating and maintenance ("O&M") costs were $7.45/kW-month, not including property taxes.[124] Thus, Norwalk's long-run average costs clearly exceed the administratively-determined $7.50 CONE used for the first FCA.[125]

Based on these factors, the Connecticut IRP concluded that energy and capacity revenues would not be sufficient to keep the Norwalk units in operation, even after the implementation of the FCM,[126] and concluded some type of reliability agreement would be needed after the implementation of the FCM, because Norwalk Units 1 and 2 (or replacement units) "may be necessary to reliability in the Norwalk area in order to protect against contingencies when one of

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[123] *See* Cost of Service Agreement Between Norwalk Power LLC, NRG Power Marketing Inc. and ISO New England Inc., Docket Nos. EL07-61-001 and ER07-799-001 (Apr. 26, 2007); Compliance Filing, Docket Nos. EL07-61-002 and ER07-799-003 (Aug. 15, 2008). *See also Norwalk Power LLC*, 120 FERC ¶ 61,048 (2007), *reh'g denied*, 122 FERC ¶ 61,273 (2008) (accepting the RMR agreement for filing, subject to refund, and setting eligibility and cost-of-service issues for settlement and, if necessary, evidentiary hearing procedures).

[124] The Brattle Group, Integrated Resource Plan for Connecticut, at A-6 (Jan. 1, 2008) (the "Connecticut IRP") *available* at http://www.ctenergy.org/pdf/REVIRP.pdf. The Connecticut IRP was prepared as part of the Connecticut Energy Advisory Board's integrated review of energy supply planning and procurement in the State of Connecticut.

[125] It is not clear that there was any new merchant capacity in the First FCA that could actually be delivered at prices equal or less than $7.50. Therefore it may well be that the "true" CONE exceeds $7.50. The Connecticut Department of Public Utility Control ("CT DPUC") recently sought project bids for peaking units, and none of the twelve offers submitted in reply had a cost of new entry less than $10.50 kW/mo. *See DPUC Review of Peaking Generation Projects*, Docket No. 08-01-01, Prosecutorial Unit, Joint Testimony of Ellen Cool, Boris Shapiro, Michael Lints, Jack Elder and Richard Levitan, Exh. B, *available at* http://www.dpuc.state.ct.us/dockcurr.nsf/6eaf6cab79ae2d4885256b040067883b/82f6fbec089e3249852574250062bb4e/$FILE/PreFiled%20Testimony%2008Apr08%20PRO.pdf. PJM recently filed to increase CONE to levels substantially above $7.50 kW/mo. *See PJM Interconnection, L.L.C.*, 123 FERC ¶ 61,015 at P 30 (2008) (rejecting request to increase the CONE for PJM regions from between $6.01-6.18/kW-month to between $8.69-8.91/kw-month on procedural grounds, while stating that "none of the intervenors dispute that the cost of constructing a new gas turbine facility has increased significantly since PJM last calculated the CONE in 2005").

[126] Connecticut IRP at A-6.

the new 345 kV transmission lines into Norwalk is out of service."[127] The results of the first FCA clearly supported this prediction, as the clearing price fell to the floor $4.50/kW-month prescribed by the FCM Settlement,[128] while Norwalk's $5.999/kW-Month Dynamic De-List Bids (the highest Dynamic De-List that Norwalk could submit under the FCM Market Rules) were rejected because Norwalk was needed for system security.[129]

For these reasons, the Filing Parties' Proposal to pay rejected Static and Dynamic De-List Bids their bids is not just and reasonable as it neither provides a reasonable opportunity for Norwalk (and other similarly situated resources whose static or dynamic De-List Bids may be rejected in the future) to recover their long-run average costs in the market, nor reflects the locational value of system security reliability service. Indeed, the Filing Parties' Proposal is nothing less than confiscatory – because it requires a resource to provide system security services without compensating it for the locational value of such services – and therefore violates the FPA under which sellers have a right to just and reasonable compensation.[130]

D. The Commission Should Require ISO-NE To Adopt The NRG Proposal For A Market-Based Compensation Mechanism Using Local Reconfiguration Auctions.

The Commission's preference in addressing reliability compensation issues is to use market-based solutions. For the reasons stated above, the Filing Parties' Proposal does not provide market-based compensation to resources with rejected De-List Bids, but instead limits them to their "net risk adjusted going forward costs." As an alternative, FirstLight and NRG

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[127] *Id*. at A-7.

[128] Forward Capacity Auction Results, filed in Docket No. ER08-633-000, at 2 (Mar. 3, 2003) ("Auction Results").

[129] Auction Results at 11-12.

[130] *See Bluefield*, 262 U.S. at 692-93; *Duquesne Light Company v. Barasch*, 488 U.S. 299, 307 (1989) (explaining the "guiding principle" that utilities cannot be compelled to accept a rate "which is so 'unjust' as to be confiscatory.").

request that the Commission order ISO-NE to adopt NRG's proposal to use Local Reconfiguration Auctions to determine a competitive market price for resources with rejected De-List Bids or, preferably, incent new transmission, generation facilities, and/or demand resources that will enable ISO-NE to accept the resources' De-List Bids. The NRG Proposal is simple, market-based, reflects the locational value of the system security service that is needed and avoids the need to use the only other practical alternative – cost-based RMR agreements.

Under the NRG Proposal, if in any FCA a Static or Dynamic De-List Bid is rejected for system security reasons, ISO-NE and the affected Transmission Owners, in conjunction with all stakeholders, will first evaluate whether there are feasible transmission solutions that can economically resolve the system security violation that resulted in the rejection, prior to the commencement of the Commitment Period. If a transmission solution is identified, the capacity associated with the rejected De-List Bid will be purchased in the first annual reconfiguration auction. If no transmission solution is identified, then a Locational Reconfiguration Auction ("LRA") would be held as part of the first annual reconfiguration auction to solicit offers for new capacity to address the system security need. The parameters of the LRA, for example the geographic area, would depend on the nature of the system security violation(s) identified.

A resource whose De-List Bid is rejected in the FCA would be required to offer its capacity in the LRA, and that offer would be unmitigated pursuant to the FCM Market Rules for reconfiguration auctions. If the Market Monitor concludes that the resource is not pivotal,[131] then the LRA would be presumed competitive and the winning resource(s) would be paid the clearing price of the highest bid needed to alleviate the security constraint. If the resource is pivotal, then the LRA clearing price will not exceed the higher of 110 percent of CONE,[132] or its

[131] Under the NRG Proposal, if some of the capacity of the resource whose De-List Bid has been rejected is required to satisfy the demand bid, then the resource is deemed to be pivotal.

[132] The CONE for the first such LRA would be $7.50/kW-month, and would be recomputed for a second and any successive LRAs based on the results of the preceding LRA and the

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rejected Static or Dynamic De-List Bid in the FCA. A price of 110 percent of CONE sends a price signal that more closely approximates the market value of the reliability service, and indicates that either a transmission solution,[133] or new capacity, is required to alleviate the system security issue while appropriately compensating the resource for the locational value of its capacity.[134]

The NRG Proposal also does not permit a generator whose De-List Bid is rejected for reliability reasons to "toggle" between market and cost-of-service rates.[135] Instead, the NRG Proposal is designed first and foremost to attract cost-effective alternative solutions to the reliability need and, failing that, to produce a market price that more accurately reflects the locational value of the system security being provided – a value neither reflected in the FCA clearing price nor the rejected De-List Bid – and is, therefore, entirely consistent with the Commission's preference for market-based solutions. By comparison, the Filing Parties' Proposal not only fails to compensate resources with rejected De-List Bids for the locational value of the reliability service they are needed to provide, but forces those resources to accept compensation based – not on voluntary bids in a competitive market – but on prescribed bids that are based on a narrow subset of the resource's actual cost of providing service. Accordingly, the Commission should direct ISO-NE to submit a compliance filing implementing the NRG

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procedures set forth in Market Rule 1 at Section III.13.2.4. The use of 110 percent of CONE is consistent with the price paid to existing resources in an auction with inadequate supply. The FCM Market Rules provide that, if an FCA has inadequate supply to meet the applicable ICR or LSR requirement, then existing resources would be paid 110 percent of CONE. *See* Market Rule 1, § 13.2.8 at Original Sheet Nos. 7314Y-7315B.

133 *See FCA Order* at P 35 ("Connecticut has ample opportunity to design a solution to any reliability constraint to allow resources whose de-list bids have been rejected for reliability to de-list.").

134 Indeed, a price of 110 percent of CONE is the price paid in the event that an FCA results in inadequate supply. *Supra* at note 132.

135 In the Matter of the Appeal Case No. 01-NE-BD-2008 (NRG Energy, Inc.), Decision Denying Appeal with Recommendations, at 5 (Jul. 16, 2008) ("Review Board Decision").

Proposal. If the Commission does not require ISO-NE to adopt the NRG Proposal, or comparable market-based mechanism, it should require ISO-NE to modify its rules to allow resources whose Dynamic or Static De-List Bids are rejected for local reliability to enter into cost-of-service RMR agreements.

E. It Is Fundamentally Unfair To Apply The Filing Parties' Proposal Retroactively To The First And Second FCAs. NRG Should Be Given The Option To Change The Bids Of Norwalk Units 1 And 2 To Rejected Permanent De-List For The First And Subsequent FCM Commitment Periods, And Existing Resources Should Be Allowed To Submit An Out-Of-Time Permanent De-List Bid In The Second FCA.

In the event that the Commission chooses not to adopt the NRG Proposal, the Commission should, at a minimum: (1) allow NRG an option to change the status of Norwalk Units 1 and 2 to "Rejected Permanent De-List" for purposes of the first Capacity Commitment Period so they can then receive the full cost-of-service compensation which ISO-NE proposes to pay to generators who permanently de-list; and (2) give any other resources that did not submit Permanent De-List Bids for the second FCA the option to do so within thirty (30) days of the Commission's order. Principles of fundamental fairness and equity require that the Commission grant such relief in this case. The FCM Settlement requires that generators whose static and dynamic De-List Bids are rejected for reliability be paid a just and reasonable compensation. At the time it submitted its bids in the first FCA, NRG did not know the specific reliability criteria that would be used to reject its Static and Dynamic De-List Bids in the first FCA, and reasonably assumed that the compensation that the Commission would determine to be "just and reasonable" for such rejected bids would continue to reflect long-standing Commission precedent, namely that resources needed for reliability would be eligible for cost-of-service rates.

Similarly, there may be other resources that desire to submit Permanent De-List Bids in lieu of Static or Dynamic De-List Bids as a result of the Commission's decision in this proceeding.[136]

Indeed, the NEPOOL Review Board (or "Board") has recognized the unfairness of subjecting Norwalk's rejected De-List Bids to the Filing Parties' Proposal and recommended a one-time review of the appropriate compensation for Norwalk and other similarly situated resources with rejected De-List Bids. The Board stated:

> The Board makes this recommendation because at the time of the auction, the then-proposed changes to Market Rule 1 had not been adopted, and, at the same time, NRG was proposing its Amendment 1. There was then some uncertainty with regard to what compensation would be provided for units making static and dynamic de-list offers in the FCA. As a matter of fundamental fairness, the Board believes that clarifying FERC's view of "just and reasonable" compensation in the subject circumstances would serve to avoid future litigation challenges premised on the lack of notice , and ensure that the "just and reasonable" standard of the FPA is met.

In the *FCM Market Rules Order*, the Commission also recognized the importance of having a plan for compensating rejected De-List Bids in place before the first FCA "to provide a more transparent rate structure for compensation of units under any potential Reliability Agreements."[137] However, as a result of the delay in submitting the Filing Parties' Proposal until after the first FCA was complete and the deadline for submitting Permanent De-List Bids in the second FCA had passed, there was no transparent rate structure from which NRG and other market participants could meaningfully evaluate whether to submit Permanent, Static or

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136 Similarly, the Commission has found that fairness dictates that partial requirements customers who made economic decisions based on incorrect rate designs should not be penalized by retroactively changing the design when they have no corresponding ability to re-make their decisions. *See Union Elec. Co.*, 58 FERC ¶ 61,247, 61,818 (1992) ("As Union and the Cities both agree, the customers cannot revisit their economic decisions. Thus, the Commission concludes that the only reasonable solution is to implement the rate design change prospectively.").

137 *FCM Market Rules Order* at P 85.

Dynamic De-List Bids. Similarly, the lack of transparency as to the standards ISO-NE would apply in rejecting Dynamic De-List Bids further hampered NRG's ability to make a fully informed decision as to which type of De-List Bid to submit in the first FCA. As is clear from the many protests filed in response to the results of the first FCA, market participants and state regulators who had actively participated in the FCM Settlement were caught by surprise when ISO-NE rejected Norwalk's Dynamic De-List Bids on the basis of TSA.[138]

Finally, the record is clear that NRG did not submit its Dynamic De-List Bids of $5.999 because it believed that amount was just and reasonable compensation. To the contrary, NRG vociferously challenged such a notion in its protests of the FCM Market Rules and sought clarification from the Commission that the limits imposed on De-List Bids for market mitigation purposes would not constitute just and reasonable compensation if those De-List Bids were rejected.[139] NRG submitted the maximum possible Dynamic De-List bids (i.e., below 80 percent of CONE or $6.00/kW-month) for Norwalk Units 1 and 2 because it was the simplest way to de-list the units,[140] and based on publicly available information about supply and demand it was clear that the first FCA would clear (and indeed did clear) well below Norwalk's Dynamic De-List Bid.[141]

Allowing NRG an option to permanently de-list Norwalk beginning with the commencement of the First Commitment Period and be paid its full cost-of-service if it is needed

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138 *FCA Order* at P 19.

139 *FCM Market Rules Order* at P 77 ("NRG seeks clarification from the commission that de-list bid do not constitute a just and reasonable rate for a generator whose bid is rejected for reliability reasons. NRG finds that these bids are not compensatory, as the level of reference costs for de-list bids does not include the fixed costs that are part of 'doing business' including debt cots, depreciation expense, and return on equity.").

140 NRG May 2 Answer at 9.

141 *Id*. at 7. The first FCA was stopped when the market price hit the floor (i.e., $4.50/kW-month) provided for in the FCM Settlement.

for reliability will not prejudice any party. The results of the first FCA would not have been any different had Norwalk submitted a Permanent De-List Bid in the first instance, and Norwalk gains no competitive advantage by being allowed to permanently de-list after the auction. In fact, allowing Norwalk an option to permanently de-list and be paid its full cost-of-service for reliability service will send a price signal to build transmission facilities or new capacity that can replace Norwalk.

There can be no reasonable dispute that Norwalk's generators have little expectation of earning enough inframarginal revenues in the energy and ancillary services markets to compensate NRG's investors for the continued operation of the facility. Indeed, Mr. Schnitzer acknowledges that as a matter of fairness, a resource that is "out of the money" from a market price point of view, but must run for reliability reasons, should have the opportunity to recover the resource's full embedded cost, including return on investment,[142] so long as it is not able to "toggle" between the higher of cost-of-service and market rates.[143] Granting the relief requested here will ensure that Norwalk has an option to receive just and reasonable compensation while assuring even the most skeptical that it will never be able to "toggle."

F. The NEPOOL Review Board's Decision Does Not Provide A Reasoned Basis For Accepting The Filing Parties' Proposal or Rejecting The NRG Proposal.

1. Background

At their June 6, 2008, meeting the Participants Committee voted to approve what is now the Filing Parties' Proposal,[144] and rejected NRG's proposal to use a focused stakeholder process to identify practicable transmission solutions to local reliability violations that lead to rejection of the De-List Bids, followed by Local Reconfiguration Auctions to determine whether there are

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142 Schnitzer Testimony at 11:2-7.

143 *Id*. at 13:14.

144 Filing Parties' Transmittal Letter at 27-28.

other qualified capacity resources to replace resources whose De-List Bids are rejected for reliability or, alternatively, determine a market-based price at which the Resource with the rejected De-List Bid will be compensated. On June 13, 2008, NRG filed with the NEPOOL Review Board a timely appeal of the Participants Committee's June 6, 2008 decision to adopt the proposal and reject the NRG Proposal.[145] On July 16, 2008, the Board issued a decision denying NRG's appeal,[146] which the NEPOOL Participants Committee filed with the Commission on July 17, 2008.

The Board's decision acknowledged that New England's capacity market is still being developed "and problems with it (both foreseen and unforeseen) will have to be addressed by the Market participants, the ISO and FERC going forward."[147] Consequently, the Board chose to review market design issues broadly, with the view that "[a] successful market design for these types of non-traditional markets should really be judged as one which the participants and the ISO can agree on, and which the Commission can approve," and "should not be judged strictly on the basis of economic theory alone."[148] Accordingly, the Board did not focus on the merits of the Filing Parties' Proposal, but on whether it resulted in "unfair or discriminatory treatment of NRG and other capacity providers with respect to rejected De-List Bids.[149]

The bases cited for the Board's rejection of NRG's appeal were that: (1) the FCM Market and its provisions for compensation in these cases are intended by FERC to provide just and reasonable compensation and there is no basis to believe that FERC intended that cost-of-

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145 Notice of Appeal to the NEPOOL Review Board from the June 6, 2008 Meeting of the Participants Committee, filed in Docket No. 01-NE-BD-2008 (June 13, 2009).

146 Review Board Decision at 4.

147 *Id*.

148 *Id*.

149 *Id*.

service level compensation is required under these circumstances;[150] (2) NRG should have submitted a Static De-List Bid reflecting its view of just and reasonable compensation and then appealed to the Commission if the Market Monitor rejected that bid;[151] (3) NRG chose to submit a De-List Bid just below the 0.8 CONE level which avoided Market Monitor review of its offer;[152] and (4) NRG will keep any inframarginal revenues obtained during the year it is required to provide capacity services in addition to its de-list offer capacity payments, providing the opportunity to realize compensatory rates.[153]

Although it found ISO-NE's revisions to Market Rule 1 to be reasonable, the Board recognized that, at the time of the first FCA, the Filing Parties' Proposal had not been adopted. As a result, the Board recommended "a one-time review of the appropriate compensation for NRG's subject units in this case as well as the compensation for other units that may have been similarly affected" by the Participants Committee, ISO-NE and the Commission.[154] The Board also stated that it understood "the potential issues raised by NRG and believes that the previously approved rules for the compensation of rejected de-list bids should be reviewed in light of the experience of the initial FCA."[155]

The Review Board Decision declined to recommend that the Participants Committee reconsider, ultimately concluding that there were two problems with the NRG Proposal, namely: (1) allowing a unit whose De-List Bid has been rejected for reliability reasons to bid again in the Reconfiguration Auction likely violates FERC's guidance that generators must not have the

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150 *Id*. at 5 (adding that "[FERC] did not specifically preclude that possibility [of cost-of-service level compensation").

151 *Id*. at 5.

152 *Id*. NRG's Norwalk Units 1 and 2 submitted "Dynamic" De-List Bids.

153 *Id*. at 6.

154 *Id*.

155 *Id*. at 5.

option to move between market or regulated rates;[156] and (2) adopting the NRG amendment would afford NRG and other generators the protection from the downside of a market without a statutory floor or cost recovery mechanism while allowing full enjoyment of returns due primarily to congestion pricing.[157] Finally, the NEPOOL Review Board made a general appeal for the use of innovative least-cost engineering solutions – as opposed to generation capacity market solutions – to address transmission reliability problems.[158]

2. The Review Board's reasons for rejecting NRG's appeal are not supported by the record.

The NEPOOL Review Board's rejection of NRG's appeal because there is no reason to believe that the Commission intended that cost-of-service level compensation is required under these circumstances is a *non sequitur*. NRG is not advocating cost-of-service compensation, except as a last resort, and is urging with FirstLight, here, the use of Local Reconfiguration Auctions to determine a market-based price that appropriately compensates resources with rejected De-List Bids for the locational value of the reliability service they provide. NRG's market-based approach is more in keeping with the Commission's reliability compensation policy. Moreover, the FCM Settlement expressly reserved the issue of what would be "just and reasonable" compensation for rejected De-List Bids and the Commission's adoption of the FCM Market Rules also expressly refused to foreclose any particular proposal for compensating rejected De-List Bids.

The Board's view that NRG could have submitted Static De-List Bids for Norwalk Units 1 and 2, based on its long-run average costs, and then appealed the Market Monitor's rejection of the bid because it exceed Norwalk's "net risk adjusted going forward costs," ignores the fact that

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156 *Id*. at 7.

157 *Id*. at 8.

158 *Id*. at 8-10.

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the Commission had just rejected NRG's protests that it ought to be allowed to submit Static De-List Bids at about 80 percent of CONE in the *FCM Market Rules Order* and subsequently denied rehearing of the same. Submitting an impermissible Static De-List Bid, and then appealing the Market Monitor's rejection of it, would have been a pointless gesture, and likely deemed a collateral attack on the *FCM Market Rules Order*.

The fact that NRG chose to submit Dynamic De-List Bids for Norwalk Units 1 and 2 at just below the 80 percent of CONE level simply has no bearing on whether that amount is compensatory, because the Commission had expressly refused to address whether the limits on Static or Dynamic De-List Bids would also be limits on compensation if those De-List Bids were rejected.[159] NRG considered challenging the ISO-NE's rules again, but concluded that such a challenge was unnecessary because the FCM Settlement and ISO-NE rules clearly permitted Norwalk to submit Dynamic De-List Bids for $5.9999/kW-month (just below 80 percent of CONE) and publicly available information on supply and demand just as clearly indicated the bid would be well above the clearing price.[160] The fact that Norwalk's Dynamic De-List Bids were not subject to Market Monitor review is equally irrelevant to this proceeding. Norwalk's fixed and variable cost information was reviewed by ISO-NE as part of its RMR application in 2003, and again as part of its pending RMR application in 2007, and is publicly available.

The Board's suggestion that inframarginal revenues obtained by Norwalk during the year, in addition to its de-list offer capacity payments, will provide the opportunity to realize compensatory rates simply defies reality. Norwalk runs almost exclusively for reliability, and almost routinely as the marginal resource. Thus it earns very, very little in the way of inframarginal revenues. Indeed, that is why Norwalk has been on either PUSH bidding or an

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159 *Supra* at note139.

160 NRG May 2 Answer at 7.

RMR agreement for the last five years. As the Connecticut IRP recognized, the combination of a $5.9999/kW-month capacity payment and negligible inframarginal revenues will provide no possibility that Norwalk can recover the costs needed to operate safely and reliably.

Finally, the Board's seeming deference to the ISO-NE and NEPOOL Participants Committee stakeholder process is wholly misplaced. The stakeholder process did not produce a consensus as to the appropriate compensation for rejected Static and Dynamic De-List Bids. This result is not particularly surprising, given that the participants in the FCM Settlement could not reach a consensus on that issue either. While consensus may be preferable, the Commission's obligation is to ensure just and reasonable rates that provide a reasonable opportunity for resources to recover their long-run average costs. For all the reasons previously discussed, the Filing Parties' Proposal does not provide Norwalk Units 1 and 2 with such an opportunity and likely will not provide other similarly situated resources such an opportunity in the future.

The two reasons given by the Board for rejecting the NRG Proposal really boil down to the apparent perception of the Board that the NRG Proposal to use Local Reconfiguration Auctions would somehow allow resources to "toggle" between cost-of-service rates and market-based rates. However, this was simply not the case. As previously discussed, a resource with a rejected Static or Dynamic De-List Bid does not get cost-of-service rates. Instead, the resource has to compete in a Local Reconfiguration Auction whose purpose is to incent lower-cost transmission or generation solutions that will enable ISO-NE to allow the resource to de-list and presumably deactivate. Accordingly, utilizing a Local Reconfiguration Auction to establish the actual market value of the reliability service to be provided when the FCA fails to do so is the antithesis of "toggling" and best accomplishes the Commission's objective of using market-based mechanisms to resolve reliability compensation issues.

VI. CONCLUSION

Wherefore, FirstLight and NRG respectfully request that the Commission reject the Filing Parties' Proposal and require ISO-NE to implement NRG's Proposal.

August 1, 2008

Respectfully submitted,

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and New England Power Pool	))	**Docket No. ER08-1209-000**

AFFIDAVIT OF
JONATHAN A. LESSER, PH.D AND DAVID W. DERAMUS, PH.D.

ON BEHALF OF
THE NRG COMPANIES

I. QUALIFICATIONS

My name is Jonathan A. Lesser. I am an economist and Partner with the Energy Practice of Bates White, LLC ("Bates White" or "the firm"), an economic and litigation consulting firm. My business address is 1300 Eye Street, N.W., Suite 600, Washington, D.C. 20005. I have 25 years' experience in the energy industry, and have worked for electric utilities, government agencies, and as an economic consultant. I have addressed numerous economic and regulatory issues affecting the energy industry, including wholesale market design, gas and electric utility structure and operations, costs and benefits of mergers and acquisitions, cost allocation and rate design, resource investment decision strategies, cost of capital, depreciation, risk management, incentive regulation, economic impact studies, and general regulatory policy. I have prepared expert testimony and reports in cases before public utility commissions in numerous states, the Federal Energy Regulatory Commission ("FERC" or "the Commission"); before regulators in Belize, Guatemala, Mexico, and Puerto Rico; in commercial litigation cases; and before legislative committees in Connecticut, Maryland, Texas, Vermont, and Washington. A copy of my curriculum vita is attached as Exhibit NRG-2.

My name is David W. DeRamus. My business address is 1300 Eye Street, NW, Suite 600E, Washington, DC, 20005. I am a Partner with the economic consulting firm of Bates White, LLC. I have been in this position since 1999. During this time period, I have performed economic analyses related to a range of litigation and non-litigation matters, most of which have pertained to antitrust and market power issues. I have previously submitted expert testimony in various FERC and state regulatory proceedings, most of which relate to issues of market power, applications for market-based rate authority, and merger applications. From 1998 to 1999, I was employed by the management consulting firm of A.T. Kearney. From 1993 to 1998, I was employed by the accounting firm of KPMG Peat Marwick in its Economic Consulting Services practice. In both firms, I performed a variety of economic and statistical analyses related to litigation and non-litigation matters. From 1990 to 1992, I was employed by the Harvard Graduate School of Business Administration as a Research Associate. I received a Ph.D. in Economics from the University of Massachusetts at Amherst, with a specialization in Industrial Organization and International Economics. My Curriculum Vitae is attached as Exhibit No. NRG-3.

II. PURPOSE OF AFFIDAVIT

In this affidavit we provide our opinions on the proposal to compensate rejected Dynamic and Static De-List Bids submitted by ISO New England Inc. (“ISO-NE”) and the New England Power Pool ("NEPOOL") Participants Committee (together, the "Filing Parties") in the above-captioned proceeding.[1] We have prepared this affidavit at the request of the NRG Companies ("NRG").[2] NRG owns and operates generating plants in ISO-NE and is concerned that the proposed rules for payments to resources whose applications to de-list are rejected for reliability reasons are neither just nor reasonable. NRG's Norwalk Units 1 and 2 were rejected for reliability reasons in the first ISO-NE Forward Capacity Auction ("FCA").

III. SUMMARY OF CONCLUSIONS

A. Filing Parties' Proposal

We have reviewed the Filing Parties' proposal for compensating Static and Dynamic De-List Bids that are rejected because they are needed for reliability ("Filing Parties' Proposal").[3] The Filing Parties propose to pay generators whose Static or Dynamic De-List bids are rejected for reliability *only* the costs they can avoid by de-listing. ISO-NE refers to these as "net risk adjusted going forward costs" which, as computed by the ISO-NE mitigation formula, are intended to approximate a generator's

1 ISO New England Inc. and New England Power Pool, Docket No. ER08-1209-000, tariff Revisions Relating to Resources Needed for Reliability in the Forward Capacity Market, July 1, 2008.

2 The NRG Companies are NRG Power Marketing LLC, Connecticut Jet Power LLC, Devon Power LLC, Middletown Power LLC, Montville Power LLC, Norwalk Power LLC ("Norwalk"), and Somerset Power LLC.

3 ISO New England Inc. and New England Power Pool, Docket No. ER08-1209-000, Tariff Revisions Relating to Resources Needed for Reliability in the Forward Capacity Market, July 1, 2008.

short-run marginal costs ("SRMC").[4] For the following reasons, the Filing Parties' Proposal is based on simplistic and erroneous economic theories and, as a consequence, will lead to prices that are unreasonable and confiscatory:

1. The Filing Parties' Proposal rests entirely on the erroneous assumption that in the Forward Capacity Market ("FCM"), the appropriate competitive price is equivalent to SRMC. However, the FCM is a long-term market with a three-year advanced commitment period, designed specifically to allow the time needed to bring new resources into the market. The appropriate compensation must therefore be based on long-run average costs ("LRAC"). There is absolutely no reason to expect firms — even in highly competitive long-term markets — to bid SRMC as ISO-NE is requiring. In fact, it would be economically irrational for a generator to agree to provide service over the long-run at a price that provides for absolutely no return of or return on its capital.

2. ISO-NE wrongly relies on a highly simplified, unrealistic, theoretical model of short-run, *perfectly* competitive markets – rather than a realistic model of long-run, real-world, *workably* competitive markets – to justify its SRMC-based compensation for generators whose de-list bids are rejected. A proposal that imposes such unrealistic requirements on

[4] Filing Parties' Transmittal Letter at 13. However, as discussed in Section VIII, flaws in the ISO-NE formula for computing "net risk adjusted going forward costs" results in the formula not even providing accurate estimates of true short-run marginal costs.

bidders whose capacity is needed for reliability is not only economically unsound, but will also send the wrong price signals and undermine the very objectives that FCM purports to achieve: maintaining and attracting sufficient capacity resources.

3. ISO-NE's argument that a generator should be paid its de-list bid because the bid was voluntarily submitted is specious. In fact, the bids are overly restrictive mitigation caps that would never form the basis for prices in a workably competitive "pay-as-bid" market.

4. The Filing Parties' Proposal will not provide generators whose de-list bids are rejected for reliability a reasonable opportunity to recover their LRAC from ISO-NE's markets, since generators whose de-list bids are rejected for reliability are typically those with high operating costs and low capacity factors. These units will earn little or no inframarginal revenues and, consequently, will be unable to recover the shortfall between LRAC and SRMC from the energy market. As a result, the Filing Parties' Proposal is confiscatory.

5. ISO-NE's formula for "risk adjusted going forward costs" is inherently flawed because it does not provide an accurate measure of either going-forward costs or SRMC. It excludes many expenses – (*e.g.*, property taxes, insurance, debt costs, a substantial portion of labor costs and additional capital and repair costs) that generators must pay to remain in

business and continue to provide the reliability benefits during the FCM commitment period.

6. ISO-NE witnesses wrongly assert that the SRMC-based compensation received by generators whose de-list bids are rejected is justified based on the "option value" those generators obtain with respect to participating in future FCMs, compared to submission of permanent de-list bids. This argument turns the economic concept of "option value" on its head. ISO-NE witnesses fail to recognize that this "option value" is inherent in the value of any asset in a competitive market with freedom of entry and exit. ISO-NE witnesses ignore the fact that, unlike a standard competitive market, the existing generators are *compelled* to participate in the auction, *compelled* to remain in the market if their de-list bids do not clear, and *compelled* to submit bids that are less than or equal to SRMC, and are compelled to either cover their obligation when unable to perform or suffer additional financial burdens. These features of the FCM create a "barrier to exist" that will significantly *reduce* the value of generating assets. Indeed, the Filing Parties' Proposal fails to compensate for the significant and real option value that generators whose de-list bids are rejected provide to ISO-NE. The option value to ISO-NE of maintaining the availability of such generators that are required for reliability purposes is based on the value of lost load, which is many times larger than a generator's SRMC.

B. NRG's Proposal

In contrast to the Filing Parties' flawed proposal, NRG's proposal is consistent with both the design of the FCM and with sound economic principles. NRG proposes to use a local reconfiguration auction to establish the price when a transmission solution to the reliability need is not found. A resource whose de-list bid would be rejected is required to bid into the LRA and, if it is deemed pivotal, would be paid the higher of 1.1 times the cost of new entry ("CONE") or the de-list bid rejected in the primary FCA. NRG's proposal will produce a form of market-based compensation that will both fairly compensate existing generators and send the correct price signals for new entry.

IV. FCM IS A LONG-TERM MARKET FOR WHICH SOUND ECONOMIC PRINCIPLES REQUIRE COMPENSATION AT LRAC.

The FCM has a three-year advanced commitment period designed specifically to allow the time needed to bring new resources into the market, including demand response resources. In supporting the FCM, ISO-NE explained that the purpose of the three-year advanced commitment period was to, "provide a planning period for new entry, so that potential new capacity resources can participate in the auction and compete with incumbent resources."[5] As the FCM Settlement underscored:

> In economic terms, the planning period increases the elasticity of the short-term supply curve (Figure 1) into an elastic long-term supply curve (Figure 2) because suppliers of capacity resources

[5] Explanatory Statement of the Settling Parties in Support of Settlement Agreement and Request for Expedited Consideration, Docket Nos. ER03-563-000, *et al*. (March 6, 2006) ("FCM Settlement"), at 27.

> can respond to price movements by changing the amount of capacity they offer in the auction.[6]

Therefore, the FCM was designed as, and ISO-NE itself considers the FCM to be, a long-term market, not a short-term one. In fact, the lead time needed for new entry into the capacity market was at the heart of the decision to design the FCM so that the primary FCA is held three years is advance of the commitment period, *i.e.*, three years was deemed a reasonable period for new suppliers to build new capacity and enter the capacity market. This was also clearly stated in the Commission's order approving the FCM Settlement:

> ISO-NE intends that the period between the Forward Capacity Auction and the supply commitment period will provide a planning period for new entry, so that potential new capacity suppliers (capacity resources) may participate in the Forward Capacity Auction and compete with existing resources. If a potential capacity resource clears the Forward Capacity Auction, it has more than three years to build the infrastructure needed to fulfill its capacity obligation.[7]

Yet, despite the fact that the FCM is a long-term market where entry is designed to provide price discipline, the FCM Settlement imposed significant limitations on existing generating capacity suppliers, so as to mitigate any potential exercise of market power. In particular, all existing capacity resources are forced to participate in the FCA and an existing capacity resource can seek to avoid this obligation only by submitting a de-list bid into the FCA -- the price below which it will not supply capacity and can then sell into other markets *(e.g.*, under a bilateral contract or into New York).

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[6] *Id.*, at 28, (Figs. and fns. omitted).

[7] *ISO New England, Inc*., 119 FERC ¶ 61,045 at ¶ 5 (2007) ("*FCM Settlement Order*").

There are four types of de-list bids – Permanent De-list Bids, Static De-list Bids, Export Bids, and Administrative Export De-list Bids – that must be submitted to ISO-NE during the qualification process in advance of an FCA, and a fifth type (Dynamic De-list Bids) that may be submitted during the FCA.[8] The ISO-NE Market Monitor reviews each Static De-list Bid and Export Bid above 0.8 times CONE, and each Permanent De-List Bid above 1.25 times CONE submitted by existing generating capacity resources.[9] The Market Monitor reviews such de-list bids to determine whether the bids are consistent with the resource's "net risk adjusted going forward costs," which as computed according to ISO-NE's formula are below true going forward costs.[10] If the Market Monitor determines that a de-list bid is inconsistent with the resource's "net risk adjusted going forward costs," that de-list bid will be rejected and the resource will be entered into the FCA as a price taker.[11] Dynamic De-list Bids must be below 0.8 times CONE, may be submitted in the FCA round and are not subject to Market Monitor review at the time they are submitted, but may be reviewed at the time ISO-NE files its report to the Commission on the results of a particular FCA.[12]

The inconsistency between the FCM long-run market design in which new entry (by generation or demand resources) up to three years into the future is presumed to

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8 *FCM Settlement Order* at P 19 and n.20; *See also* ISO-NE FERC Electric Tariff No. 3, Section III ("Market Rule 1") at § 13.1.2.3.1.1.

9 Market Rule 1 at § 13.1.2.3.2.

10 *Id.*

11 *Id.*

12 *Id.*

provide the supply needed to keep prices at competitive levels, while bids from existing capacity resources are mitigated to SRMC, is the fundamental economic flaw in the Filing Parties' Proposal. ISO-NE cannot, on the one hand, claim that the FCM is a long-term market, but then reimburse generators whose static and dynamic de-list bid were rejected based only on short-run avoided costs. Economic theory supports the premise that suppliers in a workably competitive long-term market, like the FCM, will bid their LRAC.[13] Simply put, in the long run, when there can be market entry and exit, generally accepted economic theory clearly states that prices in competitive markets are expected to converge on LRAC, including a "normal" return on and of capital.[14] Consequently, generators whose bids are rejected for reliability reasons should be compensated based on long-run average costs, *i.e.*, their own LRAC, or at an administratively determined long-run equivalent such as CONE. Accordingly, the Filing Parties' Proposal is flatly inconsistent with fundamental economic principles.

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[13] For a discussion of short-run vs. long-run, *see, e.g.*, Kahn, Alfred, <u>The Economics of Regulation: Principles and Institutions</u>, pp. 70-74; *See also*, Bonbright, James, (1961), <u>Principles of Public Utility Rates, p. 324</u> ("[W]hat distinguishes long-run from short-run marginal cost is that the former cost is measured under the assumption of a *sustained* increment in the rate of output-sustained for a period sufficiently long to require, or at least to justify, a change in the capacity and design of the plant and equipment. This means that those capital and operating costs which are treated as constant, and hence are excluded, in short-run cost analysis, are here treated as variable.")

[14] *See, e.g.,* Scherer, F.M. and Ross, David (1990), <u>Industrial Market Structure and Economic Performance</u>, 3rd ed., pp. 19-20: In long-run equilibrium, "New firms attracted by the profit lure will enter the industry, adding their new marginal cost functions to the industry's supply curve, and existing firms will expand their capacity, so the industry supply curve shifts to the right. Entry and expansion will continue, augmenting output and driving the price down, until price has fallen into equality with *average total cost (ATC) for the representative firm...(including the minimum necessary return on its capital)*" (emphasis added).

Ultimately, ISO-NE has erred by focusing on the time period for rejected de-list bids (one year) without considering the lead time when such decisions are realized. For example, whereas suppliers decisions about tomorrow's day-ahead energy market would rightly be considered within the realm of the short-run since capacity is fixed, the day-ahead market three years from now would be considered the long-term, even though the operating period for the market is just twenty-four hours. It is the ability to make decisions about entering or exiting a market that characterizes the long run, not the duration of the market itself, whether one year or one day.

Moreover, a capacity resource whose Permanent De-List Bids are rejected for reliability reasons can choose to receive its de-list bid or can file to collect its full cost-of-service. In contrast, Static and Dynamic De-List Bids that are rejected for reliability reasons will receive only their "net risk adjusted going forward costs." The Filing Parties' Proposal is, therefore, impermissibly discriminatory insofar as it provides an arbitrarily higher level of compensation to permanent de-list bids (*i.e.*, LRAC) than to static and dynamic de-list bids for the same reliability service. A competitive market should produce a uniform market clearing price based on the locational value of the capacity service being provided, and not based on the short-run marginal costs of the resources providing the service.

Adopting the Filing Parties' Proposal for different compensation schemes based on the artificial distinction between permanent de-list bids and static/dynamic de-list bids may also result in higher costs to consumers because a resource that has no likely opportunity to recover its long-run average costs in the market may be effectively forced to exit the FCM on a permanent basis by submitting a permanent de-list bid. If that resource is needed for system security, it may be many years (at least three) before the resource is allowed to de-list. By that time, market conditions may be such that the resource has an opportunity to recover its costs, but is forced to deactivate or retire because it is ineligible for capacity payments due to its permanent de-listing. This may result in higher costs to consumers if the cost to replace the permanently de-listed resource is higher than its long-run average costs.

Also, compensating resources with rejected static and dynamic de-list bids at rates that reflect a competitive long-run market outcome, while allowing them to remain in the FCM once they are no longer needed for reliability, does not constitute "toggling" between market rates and cost-of-service rates. Rather, it constitutes providing such resources with a reasonable opportunity to recover their long-run average costs by providing market-based rate compensation for the reliability service they provide.

V. ISO-NE WRONGLY RELIES ON A HIGHLY SIMPLIFIED MODEL OF ECONOMIC THEORY TO JUSTIFY ITS CONFISCATORY COMPENSATION FOR GENERATORS WHOSE DE-LIST BIDS ARE REJECTED

ISO-NE's argument that economic theory presumes a bidder will "willingly" submit bids equal to the costs he would avoid by de-listing is incorrect because it embodies a fundamental economic misconception about bidder behavior in market auctions. Moreover, the argument relies on a highly simplified model of economic theory – a simple short-term market model that assumes the theoretical ideal of *perfect* competition, not the reality of *workable* competition. This model is *at best* (if at all) applicable to short-term spot markets, not to *long-term forward capacity markets with an obligation three years into the future*.

In a theoretical world of perfectly competitive uniform-price markets with an infinite number of sellers and buyers, none of whom are sufficiently large to affect market clearing prices through their bids or offers, each seller can be expected to supply a product at a price just equal to its marginal cost of production.[15] By the same token, in perfectly competitive markets, each buyer can be expected to purchase a product at a price just equal to the marginal value it places on the product. Perfect competition assumes that all market participants possess perfect information at all times, entry and exit is costless, and supply is not "lumpy."[16] These highly stylized conditions of *perfect* competition are simply not present in real, *workably* competitive markets,[17] including not only the FCM but also all of the other electricity markets operating throughout the U.S. As noted by Paul Joskow, "[c]reating a reasonably competitive generation market is certainly an important policy goal. However, creating a *perfectly* competitive generation market is not a realistic goal. The spatial attributes of generation markets and changing

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15 *See*, *e.g.*, Scherer and Ross (1990), pp. 19-20.

16 *See*, e.g., Carlton, Dennis and Jeffrey M. Perloff (1999), Modern Industrial Organization, 3rd ed., p. 57.

17 The pioneering literature on "workable competition" includes: Clark, J. M. (1940), "Toward a Concept of Workable Competition," *The American Economic Review*, 30:2, 241-256; and Bain, Joe S. (1950), "Workable Competition in Oligopoly: Theoretical Considerations and Some Empirical Evidence," *The American Economic Review*, 40:2, 35-47.

network conditions virtually assure that generation markets will never be perfectly competitive under all system conditions."[18]

Absent conditions of theoretical perfect competition, it is reasonable to expect that, even in workably competitive *short-term* markets, suppliers will not submit bids at their expected short-run marginal costs. Instead, suppliers will make decisions that include the appropriate economic trade-off between the marginal gains from raising bids above marginal costs and the marginal losses from foregone profits should bids above marginal costs not be accepted. Simply put, bidding above marginal costs – especially short-run marginal costs – is an inevitable and necessary consequence of suppliers acting in an economically rational manner by attempting to maximize their ability to earn a return that will compensate investors for the financial risk to their capital in all real-world markets, including markets that are workably competitive.[19] This expectation is also consistent with empirical observation: several studies of energy markets show that suppliers bid above marginal costs in many power markets with different structures and

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[18] Joskow, Paul L. (1997), "Restructuring, Competition, and Regulatory Reform in the U.S. Electricity Sector," *Journal of Economic Perspectives*, 11:3, 119-138, p. 135.

[19] *See, e.g.*, Klemperer, Paul D. and Margaret A. Meyer (1989), "Supply function Equilibria in Oligopoly under Uncertainty," *Econometrica*, 57, 1243-1278; Ausubel, Lawrence M. and Peter Cramton (2002), "Demand Reduction and Inefficiency in Multi-Unit Auctions," Working Paper, University of Maryland; Cramton, Peter (2004), "Competitive Bidding Behavior in Uniform-Price Auction Markets," *Proceedings of the Hawaii International Conference on System Sciences* (January) ("Cramton 2004") http://www.cramton.umd.edu/papers2000-2004/cramton-bidding-behavior-in-electricity-markets-hawaii.pdf.

rules, including PJM, New York, New England, and ERCOT.[20] Indeed, as noted by Professor Peter Cramton, "[a]s a matter of economic theory and sound market design for wholesale electricity bid-based auction markets, there is and should be no competitive norm stipulating that suppliers' bids should equal marginal costs."[21]

A market rule that requires suppliers to bid, and compensates them for, only their SRMC – *particularly* in a long-run market such as the FCM – is not only economically unrealistic, but also sends the wrong price signals.[22] Compensating units needed for reliability at only their short-run marginal costs undercuts the appropriate long-run price signal – long-run average cost, as discussed above – that is necessary to provide adequate incentives for transmission solutions, new generating capacity, or demand response measures to address the reliability problem. This, in effect, subsidizes the failure to

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[20] *See*, *e.g.*, Bushnell, James and Celeste Saravia (2002), "An Empirical Assessment of the Competitiveness of the New England Electricity Market," Working Paper, CSEM-101, UC Berkeley; Mansur, Erin T. (2001), "Pricing Behavior in the Initial Summer of the Restructured PJM Wholesale Electricity Market," POWER Working Paper-083, UC Berkeley; Krantz, Bradley, Robert Pike and Eric Hirst (2002), "Integrated Electricity Markets in New York: Day-ahead and Real-time Markets for Energy, Ancillary Services, and Transmission," New York ISO; Fabra, N., N. von der Fehr, and D. Harbord (2006), "Designing Electricity Auctions," *RAND Journal of Economics*, 37(1):23-46; Sioshansi, R. and S. Oren, "How Good are Supply Function Equilibrium Models: An Empirical Analysis of the ERCOT Balancing Market," *Journal of Regulatory Economics*, Vol 31, No 1, pp 1-35, February, 2007, *available at*. http://www.ieor.berkeley.edu/~ramteen/papers/sfe.pdf.

[21] Cramton (2004).

[22] *See, e.g.*, Cramton, Peter and Steven Stoft (2007), "Why We Need to Stick with Uniform-Price Auctions in Electricity Markets," *The Electricity Journal*, 20:1, 26-37. "Why shouldn't we try to hold everyone's spot price down to their variable cost? This will be taken up in detail later, but the answer is virtually self-evident: because no investor would ever build a plant if fixed costs were not recovered. When the market is in equilibrium, uniform prices simply cover variable plus fixed costs. That cannot be argued with." (p.29).

properly plan and construct the transmission system to prevent the occurrence of such reliability problems. As ISO-NE witness Mr. LaPlante himself stated in his May 21, 2008 remarks to the Commission at a Technical Conference on compensation for demand response resources,

> An efficient market clears at the price where the marginal cost of production is equal to the marginal benefit of consumption. For the electricity markets to be efficient, all resources must be priced at their marginal value. **…** As we develop market rules for compensating Demand Resources, it is essential to apply these market principles. If not, we risk inefficient production and consumption decisions. For example, if demand response is undercompensated, there will be too much supply and prices will be too high. However, if demand response is overcompensated, then efficient production will go unused, prices will be too low and investment in new resources may not occur.[23]

We agree. Applying market principles *is* essential for a well-functioning market. And it is those same market principles that imply that it would be economically irrational for a generator to agree to provide service over the long-term at a price that provides for absolutely no return of or return on its capital. Therefore, forcing current generators to bear such a subsidy by the imposition of *below market prices* – as in the Filing Parties' Proposal – will necessarily result in an artificially reduced supply of capacity below the efficient level that would prevail in a competitive equilibrium. This reduction in supply will come either from existing generators who choose to retire or permanently de-list rather than choosing to maintain their capacity in the market in future periods or from

[23] Demand Response in Organized Electric Markets Technical Conference, Docket No. AD08-8-000, Panel 1 – Value of and Appropriate Compensation for Demand Response in Organized Electricity Markets, Remarks of David LaPlante, May 21, 2008, at 1.

potential new entrants who choose not to enter the market as a result of the increased risks that they will be similarly treated in the future.

VI. COMPENSATING GENERATORS WHOSE DE-LIST BIDS ARE REJECTED BASED ON MITIGATION CAPS BEARS NO RESEMBLANCE TO PRICES IN A WORKABLY COMPETITIVE "PAY-AS-BID" MARKET

ISO-NE's argument that a generator should be paid its de-list bid because the bid was "voluntarily" submitted is specious. In fact, these bids are part of a comprehensive mitigation proposal that would never form the basis for prices in a workably competitive "pay-as-bid" market. Thus, in arguing that it is appropriate to pay the generators the bids that were involuntarily computed in accordance with ISO-NE's mitigation formula, ISO-NE witnesses ignore the crucial fact that ISO-NE will be paying *"pay-as-bid"* prices that were submitted into a *uniform price* auction – a classic "apples-and-oranges" confusion of auction structures. While a generator in a market with *excess* capacity, for example, may choose to bid its SRMC in a uniform price auction for a short-run market (*e.g*,, day-ahead energy) in order to be selected *and then receive the market clearing price*, a generator that is *voluntarily* bidding into a "pay-as-bid" market will bid at what it estimates the market clearing price to be.[24] It would be economically irrational for a

[24] In defending the use of uniform price auctions rather than "pay-as-bid" auctions in California electricity markets, the "Blue Ribbon Panel" made the following observation: "The critical assumption [of the proponents of a shift to pay-as-bid markets] is, of course, that after the market rules are changed, generators will bid just as they had before. *The one absolute certainty, however, is that they will not.* Knowing that unless they changed their bidding practice under the new system they would receive only their avoidable costs on their successful bids – yielding them no contribution to their fixed or common cost, let alone profits – they obviously will universally change their practice immediately, bidding instead at what they *expect* will turn out to be the market-clearing price…" Kahn, Alfred

generator in a "pay-as-bid" market to offer to sell at less than what it believes is the market clearing price.[25] Thus, ISO-NE's proposal to pay generators the bids they are forced to offer in a uniform price auction on a "pay-as-bid" basis is unreasonable and does not reflect the outcomes expected in workably competitive markets – particularly given the significant constraints (the below-cost requirement) imposed on the bids submitted by market participants and the compulsory participation by generators in the FCM process.

Indeed, these two characteristics of the FCM – the compulsory participation by generators in the FCM process and the artificial, below-market constraints placed by ISO-NE on de-list bids – remove any economic rationale that the "pay-as-bid" framework is adequate, market-based compensation. The reliance on such bids in this context begs the more fundamental question of whether bidders were ever even *allowed* to submit bids that would be consistent with competitive markets and that are sufficiently high so as to be compensatory, *i.e.*, allowing them to recover long-run average costs. ISO-NE cannot avoid addressing this fundamental economic question by taking refuge in a tautology of its own creation; in other words, the Commission cannot rely on ISO-NE's circular

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E., Peter Cramton, Robert Porter, and Richard Tabors (2001), "Pricing in the California Power Exchange Electricity Market: Should California Switch from Uniform Pricing to Pay-as-Bid Pricing?," Blue Ribbon Panel Report (Commissioned by the California Power Exchange) (emphasis in original).

[25] As noted by Cramton and Stoft in discussing the merits of uniform price auctions over pay-as-bid auctions: "The law of one price plays a crucial role. It is not a law of nature, but it is a law that all competitive markets follow. […] Efforts to introduce price discrimination may succeed in the short-run, but in the long-run investment incentives are damaged and consumer costs are increased." Cramton and Stoft (2007), p. 36.

argument that, "this form of compensation must be just, reasonable, and consistent with market principles, since the rejected de-list bidders submitted these bids themselves."

VII. ISO-NE'S PROPOSAL WILL NOT PROVIDE GENERATORS WHOSE DE-LIST BIDS ARE REJECTED A REASONABLE OPPORTUNITY TO RECOVER THEIR LRAC FROM ISO-NE'S MARKETS

Significantly, generators whose de-list bids are rejected for reliability are typically those with high operating costs and low capacity factors, like the Norwalk Harbor units. These units will earn little or no inframarginal revenues and, consequently, will be unable to recover the shortfall between LRAC and SRMC from the energy market. As a result, ISO-NE's proposal will not afford these generators a reasonable opportunity to recover their LRAC from ISO-NE's markets over the long run. Therefore, ISO-NE's proposal is confiscatory.

Not only will existing resources whose de-list bids are rejected for reliability recover only their SRMC from FCM revenues, they will have little or no opportunity to recover the shortfall between LRAC and SRMC from the energy market. In particular, the results of the first FCA demonstrate that capacity resources with rejected de-list bids are typically going to be those with high operating costs and low capacity factors (like NRG's Norwalk units) and, as a result, these units will earn little or no inframarginal revenues in the energy market. Indeed, the recent Integrated Resource Plan for Connecticut, prepared at the direction of the Connecticut Light and Power Company ("CL&P") and the United Illuminating Company ("UI"), found that Norwalk Harbor's fixed O&M costs were $7.45/kW-month, not including property taxes, and that energy and capacity revenues would not be sufficient to keep the units in operation, even after the implementation of the FCM.[26] As a result, CL&P and UI concluded that some type of reliability agreement would be needed after the implementation of the FCM because the Norwalk Harbor units (or replacement units) "[m]ay be necessary to reliability in the Norwalk area in order to protect against contingencies when one of the new 345 kV transmission lines into Norwalk is out of service."[27]

Consequently, ISO-NE's proposal will not provide existing generators whose bids are rejected for reliability with a reasonable opportunity to recover their LRAC, including a return of and on capital, from the ISO-NE markets in the long run.

VIII. ISO-NE'S FORMULA FOR CALCULATING "NET RISK ADJUSTED GOING FORWARD COSTS" IS INHERENTLY FLAWED AND DOES NOT PROVIDE AN ACCURATE MEASURE OF EITHER TRUE GOING FORWARD COSTS OR SRMC

ISO-NE's formula for "net risk adjusted going forward costs" fails to provide an accurate measure of going forward costs or even SRMC. Among other things, ISO-NE's formula: (1) effectively excludes altogether many expenses (*e.g.*, property taxes, insurance, debt costs and a substantial portion of labor costs) that generators must pay to remain in business, even if the capacity is delisted for one year; (2) relies on historical average cost data for items such as inframarginal revenues ("IMR"), which can vary greatly year to year, making it unlikely that historical data will be at all reflective of the IMR to provide reliability service three years into the future, even before considering the

[26] The Brattle Group, Integrated Resource Plan for Connecticut, at A-6 (Jan. 1, 2008) (the "Connecticut IRP") *available* at http://www.ctenergy.org/pdf/REVIRP.pdf. The Connecticut IRP was prepared as part of the Connecticut Energy Advisory Board's integrated review of energy supply planning and procurement in the State of Connecticut.

[27] Connecticut IRP at A-7.

potential for new environmental regulations that could not have been quantified at the time of the offer three years prior; (3) does not reflect the locational value of the reliability service provided by the generator whose de-list bid is rejected -- and it is uncontroverted that NRG's de-list bids for Norwalk Harbor were rejected specifically because of a *local reliability need*; (4) fails to account for the opportunity cost to a generator whose de-list bid was rejected for reliability and who must then forego sales into other capacity markets; (5) fails to compensate a generator specifically retained for reliability purposes at a level that does not compromise its ability to perform when called upon, because it provides for no means to recover from equipment failure; and (6) fails to compensate generators needed for system security for locational risks that, because they coincide with the specific location of such generators, cannot be hedged.

Under Market Rule 1, generators who submit static or export de-list bids above 0.8 times CONE or permanent de-list bids above 1.25 times CONE must demonstrate that the bids are consistent with their "net risk adjusted going forward costs," which ISO-NE defines as a subset of SRMC.[28] However, ISO-NE's formula for true adjusted going forward costs does not provide an accurate measure of either going forward costs or SRMC.

The formula for calculating "net risk adjusted going forward costs" is spelled out under Market Rule 1.[29]

[28] Defined in Market Rule 1, § 13.1.2.3.2.1.1.

[29] *Id.*

$$GFC_{RA} = \left[\left(\frac{GFC}{(1 - EFOR_D)} \right) + RF - (IMR - PER) \right] x(1+i)^4 ,$$

where: GFC_{RA} = net risk-adjusted going forward cost;
$EFOR_D$ = forced outage rate;
RF = "risk factor"
PER = peak energy rents
IMR = infra-marginal rents
i = inflation rate

In essence, the "net risk adjusted going forward costs" formula adjusts a generator's historic short-run variable O&M expenses by the expected forced outage rate, adds a "risk factor" based on the probability the unit would suffer a forced outage and need to purchase replacement capacity, and subtracts the difference between historical IMR and estimated peak energy rents for the hypothetical peaking unit used to establish CONE.

Exhibit NRG-4 is a copy of ISO-NE's *De-List Data Submittals Guideline* ("*De-List Guide*"). The *De-List Guide* clearly states that only those portions of O&M and A&G expenses that can be avoided if the resource did not remain listed are considered in "net risk adjusted going forward costs."[30] Since ISO-NE uses a short-run framework for "net risk adjusted going forward costs," it excludes altogether many expenses generators must pay to remain in business and that are legitimate, long-run expenses. The "net risk adjusted going forward costs" estimate assumes that most of a generator's costs are fixed for that year, *i.e.*, that the generator cannot exit the industry, while ignoring the fact that having to make such an "exit or stay" decision three years hence is a long-term decision.

30 *De-List Guide* at pp 3, 6 and 7.

In order to be able to meet its FCM obligation and continue to provide reliability benefits even for the single year, a generator cannot simply suspend property tax payments and it cannot, for example, release all plant personnel and expect to rehire them one year later. A generator cannot suspend its insurance payments on the plant and operating personnel. A generator may also incur additional costs in the form of degradation to the facility's equipment, hastening the need for capital additions that would not otherwise occur during the proposed de-list year, *but for* the requirement that the unit be able to continue to operate. Yet, the *De-List Guide* clearly states that capital costs and expenses associated with major repairs to restore decreases in capacity or to maintain compliance with the resource's operating permit are classified as "opportunity costs" and are not included in "net risk adjusted going forward costs."[31]

In addition, the formula does *not* compensate generators for the return of or a return on capital and, in fact, explicitly states that debt costs cannot be included. By prohibiting generators from recovering their debt service costs, the Filing Parties' Proposal imposes significant financial risk on generators and their creditors. This is because, in accepting the duty to operate, to offer energy into the day ahead and real time energy markets, and to maintain the resource for the benefit of New England ratepayers, the resource assumes significant business risk that carries monetary consequences not compensated by the "net risk adjusted going forward costs" formula.[32] For example,

[31] *De-List Guide* at 7.

[32] *See, e.g.,* South Carolina Gas and Electric Company's Response To Deficiency Letter, Docket Nos. ER07-423-000, *et al*., at 1 (Mar 12, 2007) ("SCE&G Response") ("To illustrate, if SCE&G were to engage an independent contractor to operate SCE&G's

these business risks include the potential that a reliability resource committed in the day-ahead energy market will incur substantial real-time replacement power costs due to a forced outage beyond its control. On August 8, 2003, NRG's Montville Facility Unit No. 3 in Connecticut, while operating under a cost-of-service RMR Agreement, was committed in the day-ahead market and then developed a tube leak (a boiler drain off the header cracked and suffered a forced outage that required Montville to pay ISO-NE more than $600,000 more to purchase real-time replacement power than it received from its day-ahead commitment. Another such business risk includes the possibility that a forced outage will occur during so-called "shortage hours" and result in decreased FCM capacity payments.[33] Business risks also include the cost of compliance with new laws and regulations enacted long after the de-list bid was submitted. For example, resources in Connecticut are facing substantial new environmental regulations.[34] Generation

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own facilities under a good utility practice standard, that independent contractor would face business risks; and the mere recovery of out of pocket O&M costs would not compensate that contractor for those business risks. Reversing the roles, and making SCE&G the contractor for facilities used for New Horizon, places on SCE&G the exact same business risks. Operating these facilities under a required standard of care - whether that standard is negligence or good utility practice or something else -- creates the risk with potential financial consequences. By operating and maintaining these facilities, SCE&G faces a financial impact if there were a breach of the duty of care which triggered compensation for damage or injury and/or regulatory sanction).

[33] FCM Settlement, Explanatory Statement at 11 ("The Settlement Agreement provides for loss of capacity compensation for capacity resources that fail to perform (subject to certain well-defined excuses) during these Shortage Events. On any critical day, a resource can have their compensation reduced up to 10% of annual FCA Payment if it is not available and, in any month, a resource can lose up to two and one-half months of its annual FCA Payment.")

[34] *See, e.g.,* Direct Testimony of Cynthia L. Karlic on behalf of Norwalk Power, LLC, Exhibit No. NRG-12, Docket No. ER07-799-000, *et al*., (Apr. 27, 2007) (describing

resources must also comply, for example, with NERC, NPCC, and OSHA standards and will inevitably incur costs in doing so. The inability to earn a return to offset the costs associated with these risks, and the failure to include them in ISO-NE's so-called "net risk adjusted going forward costs," can and will result in some reliability resources not recovering their fixed costs and having to shut down. The costs associated with these risks, for the most part, can be avoided by de-listing and are significantly higher for resources being forced to accept a year-long commitment to operate three years hence, as compared to a resource in a short-term market that is being required to operate the next hour or next day. The Commission has recognized that requiring public utilities to assume these types of risks requires a commensurate return and has approved the inclusion of management fees to cover those risks.[35]

The Filing Parties' Proposal does not allow these costs to be recovered under its "net risk adjusted going forward costs" formula --- costs related to a risk that cannot be hedged by definition because of the generator's location. In other words, if a generator is required for reliability precisely because of where it is, it cannot "hedge" against the costs of a forced outage and the need to purchase replacement capacity from ISO-NE, because there are no replacement resources. ISO-NE's "risk-factor" adjustment is not adequate compensation for this unhedgeable risk.

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anticipated environmental compliance expenditures that Norwalk expects to have to incur in order to continue to operate).

35 *South Carolina Electric & Gas Company*, Docket No. ER07-423-000 (Apr. 20, 2007) (letter order approving facilities agreement); *High Island Offshore System, L.L.C.*, 110 FERC ¶ 61,043, *reh'g* 112 FERC ¶ 6,0150 (2005); *Tarpon Transmission Co.*, 57 FERC ¶ 61,371 (1991).

Furthermore, not compensating generators for a return of or on capital will signal bondholders that, three years' hence, the generator's revenues may not include any allowance for debt service, and this obviously raises the risk that a generator will violate its bond covenants. The result may be that bondholders will call the bonds immediately, precipitating a financial crisis that forces the generator into bankruptcy. Such an outcome would also send a negative signal to potential future market entrants, who will eventually be treated as existing generators, that the risks of capacity investment in ISO-NE are significantly increased as a result of ISO-NE's formula, thereby reducing incentives for new entry and aggravating future capacity shortages and reliability problems. As a result, ISO-NE's formula does not produce a reasonable measure of the going-forward costs which generators will actually face and significantly increases the financial risks faced by current market participants and potential new entrants.

Moreover, the formula does not even provide an accurate measure of SRMC. For example, IMR (equal to the difference between variable fuel and O&M expenses and the market clearing price) can vary greatly from year to year, making it unlikely that historical data will bear any relationship to the IMR earned during the Capacity Commitment Period. This is particularly true for Norwalk Harbor, whose historical revenues reflect Peaking Unit Safe Harbor ("PUSH") bidding. Under PUSH, Norwalk Harbor was permitted to submit bids which gave Norwalk Harbor the opportunity to recover its full cost of service per MWh of its low load factor output. PUSH has now been eliminated, and the margins earned under PUSH far exceed a reasonable estimate of future IMR for Norwalk Harbor.

Also, the inflation adjustment places significant risk on the generator. ISO-NE uses the most recent reported 1-Year Constant Maturity Treasury Rate at the beginning of the qualification period.[36] The published yields on 1-Year Constant Maturity Treasury

FIGURE 1: Yield on 1-Yr Constant Maturity Treasury Bills (January 2003- July 2008)

Source: Federal Reserve Board, Publication H.15, Selected Interest

Bills for 2003 to date are shown in Figure 1. The qualification period precedes the applicable FCA by nine months and, therefore, the inflation factor related to a Capacity Commitment Period three years after an FCA will be based on data which is almost four years old. For example, the yield on April 1, 2004 was 1.23 percent, while the yield on April 2, 2007, three years later, was 4.92 percent. If the Capacity Commitment Period were in 2007, the inflation adjustment would be 1.23 percent, even though the actual

36 *De-List Guide* at 5.

inflation is 4.92 percent. Moreover, general inflation rates are a poor measure of inflation in a given production sector. By contrast, PJM's offer cap calculation of "avoidable cost" uses a ten-year historical average using the industry-specific Handy-Whitman Index, as well as an automatic ten percent adjustment factor that provides a margin of error in case of understating costs.[37] If bids are to be a meaningful reflection of SRMC, generators must have a reasonable opportunity to reflect market conditions at the time service is rendered.

IX. TEMPORARY DE-LIST DECISIONS PROVIDE OPTION VALUE TO ISO-NE FOR WHICH ISO-NE DOES NOT COMPENSATE GENERATORS

In his testimony, Mr. LaPlante states that a static de-list bid can be thought of as purchasing an option to stay in the capacity market, rather than permanently de-list.[38] This argument is incorrect, because it turns the economic concept of "option value" on its head. In a competitive market, resources have the freedom to enter and exit the market. Any "optionality" embedded in the right to enter and exit the market, or reenter at a future date, is inherent in the value of any enterprise in any market without barriers to entry or exit – it is not a newly-created property right, as ISO-NE would have us believe.

Because an existing generator is *compelled* to participate in the FCM, it faces, in actuality, a "barrier to exit," for which it is assigned a long-term capacity obligation and for which, as we have stated, it is inappropriately compensated at "net risk adjusted going

[37] PJM Tariff, Attachment DD, § 6.8.

[38] LaPlante Testimony, at 15 ("If the resource believed that the value of the option to stay in the market in future years exceeded the cost of maintaining that option for one year, it would submit a one-year de-list bid.").

forward costs." In a competitive market, resources have the freedom to enter and exit the market. However, existing resources in the FCM are precluded from voluntarily leaving the market because they are needed for system security. This is because resources who wish to leave must submit de-list bids which, if those resources are needed for local reliability, will be rejected – even though the resources are not needed to satisfy resource adequacy requirements and their de-list bids cannot set the FCM clearing price. In short, the FCM rules eliminate an essential element of a competitive market in order to provide ISO-NE with an option to call on any resource that it needs for system security reliability and prevent such a resource from exiting the market.

In point of fact, forcing generators to submit de-list bids to exit the market – bids that ISO-NE can reject for reliability reasons – provides ISO-NE with tremendous option value. That value is substantially more than the short-run marginal costs of the resource whose de-list bid is rejected. The value of that option is equal to the difference between the expected cost of an outage if the resource were not available to maintain system security and the cost of replacing the resource.[39] Having the ability to retain existing

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[39] Mathematically, the value of this option can be expressed as: max{0, VOLL – C}, where "VOLL" equals the value of avoiding a loss of load (*i.e.*, a system outage) and "C" equals the total compensation paid to de-list generators used to maintain system security. Thus, the lower ISO-NE can restrict the compensation it pays to rejected de-list generators, the greater will be its option value. Moreover, the VOLL is typically extremely high. For example, a literature review by Peter Cramton and Jeffrey Lien, which is available on the ISO-NE website, found VOLL estimates between $2,400/MWh and $20,000/MWh (1999). *See,* Peter Cramton and Jeffrey Lien, "Value of Lost Load," February 14, 2000. Available at: www.iso-ne.com/committees/comm_wkgrps/inactive/rsvsrmoc_wkgrp/Literature_Survey_Value_of_Lost_Load.rtf. By comparison, a CONE value of $7.50/kW-month is equivalent to a price of just over $10/MWh, assuming a 30 day month.

capacity rather than losing it permanently provides value to ISO-NE and its customers for the locational value of the resource to system security, for which ISO-NE's "net risk adjusted going forward costs" formula provides no compensation.

X. NRG'S PROPOSAL IS CONSISTENT WITH BOTH THE DESIGN OF THE FCM AND WITH SOUND ECONOMIC PRINCIPLES

The Commission has recognized that resources can and should be paid a price that is higher than marginal cost to reflect scarcity, since scarcity pricing is both consistent with pricing in competitive, non-regulated markets and provides a critical market signal for new investment. This is why, as an alternative to ISO-NE's economically unsupported proposal, NRG proposes to use a local reconfiguration auction ("LRA") to establish the price when a transmission solution to the reliability need is not found. A resource whose de-list bid is rejected is required to bid into the LRA and, if it is deemed pivotal, would be paid the higher of 1.1 times the initial CONE of $7.50/kW-month or the de-list bid rejected in the primary FCA. NRG's proposal to set the price at a floor of 1.1 times CONE is supported by sound economic principles and will produce a form of market-based compensation that will both fairly compensate existing generators and send the correct price signals for new entry.

Under NRG's proposal, ISO-NE will clear the FCA without the capacity associated with the rejected de-list bid and without an equivalent quantity of installed capacity requirement, thus eliminating the artificial reduction in clearing prices which presently occurs as a result of retaining the generator whose de-list bid was rejected in the auction as a price taker. ISO-NE will then evaluate the potential for alternative solutions to address the reliability concerns that caused the de-list bid to be rejected. Thus, rather than simply relying on the generator whose de-list bid was rejected to meet the reliability need, ISO-NE would, in consultation with NEPOOL stakeholders and regulatory agencies, solicit and evaluate alternative cost-effective solutions (primarily transmission upgrades) that could be implemented in time for the start of the applicable Capacity Commitment Period.

If a transmission solution is found, the capacity associated with the rejected de-list bid will be purchased in the first annual reconfiguration auction. If no transmission solution is found, ISO-NE will conduct an LRA immediately preceding the first annual reconfiguration auction applicable to the relevant Capacity Commitment Period. The generator whose de-list bid was rejected by ISO-NE would be required to bid into the LRA and, if that resource is found not to be pivotal by the market monitor, the reconfiguration auction would be presumed to be competitive and the reliability need would be met by purchasing the needed capacity at the price at which the auction clears. If the generator whose de-list bid was rejected is found to be pivotal, the auction price would be set at the higher of 1.1 times the initial CONE of $7.50/kW-month or the rejected de-list bid in the prior primary FCA.

Setting the price when the supplier is pivotal at a floor of 1.1 times CONE sends an efficient price signal to new resources that new capacity is required. Moreover, since CONE is the presumed cost to develop new capacity, setting the price below CONE is not supported by sound economics because it would effectively require the market-clearing price to be below the established long-run average cost of new entry. Lastly, the

FCM pricing rule currently used when there is insufficient supply in the primary FCA requires that existing generators be paid at 1.1 times CONE -- precisely what NRG proposes as a floor when the generator is pivotal.

XI. THE NEPOOL BOARD OF REVIEW DECISION REJECTING NRG'S AMENDMENT IS ECONOMICALLY UNSOUND.

The NEPOOL Board of Review's ("Review Board") decision to reject the NRG proposal was not supported by reasoned analysis.[40] In its rejection, the Review Board states that:

> A successful market design for these types of non-traditional markets should really be judged as one which the participants and the ISO can agree on, and which the Commission can approve. A successful market design should not be judged strictly on the basis of economic theory alone.[41]

This logic stands for the proposition that a successful market design is one which the majority approves, rather than one based on sound economic principles. Without a foundation in sound economics, a market will neither provide accurate price signals to existing and potential market participants, nor be competitive. Indeed, a market design that does not provide correct economic incentives will produce economically inefficient outcomes that harm customers in the long-run. Moreover, the Review Board's "consensus rules" logic is wholly contradictory with its later statement that a well functioning market requires that forward price signals be the product of the free interplay

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[40] In the Matter of the Appeal Case No. 01-NE-BD-2008 (NRG Energy, Inc.), Decision Denying Appeal with Recommendations, July 16, 2008 ("Review Board decision").

[41] Review Board decision, at 4.

of supply and demand[42] – a competitive outcome which is impossible unless the market design is sound.

Citing to the Commission orders which hold that resources should not be allowed to switch back and forth between cost-of-service and market-based rates, the Review Board states:

> allowing a unit whose de-list bid has been rejected for reliability reasons to bid again in the Reconfiguration Auction likely violates FERC's guidance that generators must not have the option to move between market or regulated rates …[and] adopting the NRG amendment would afford NRG and other generators the protection from the downside of a market . . . while allowing full enjoyment of returns due primarily to congestion pricing.[43]

The Review Board's claim that the NRG amendment would violate Commission policy by allowing generators to "toggle" between market and regulated rates is factually incorrect. In fact, the NRG amendment would require the use of an auction process to establish *market-based compensation* and does not advocate or rely on cost-of-service pricing in any way. Clearly, therefore, NRG's proposal does not violate and, indeed, is fully consistent with Commission policy.

XII. CONCLUSION

ISO-NE's proposal is inconsistent with economic principles applicable to long-term markets like FCM, does not provide appropriate market price signals, will not afford generators whose de-list bids are rejected for reliability a reasonable opportunity to recover their LRAC, and is confiscatory. Furthermore, ISO-NE's proposal will

[42] *Id.* at 7.

[43] *Id.* at 7-8 (citations omitted).

undermine the objectives of the FCM by suppressing market incentives for new entry while causing existing capacity to permanently exit the market on an expedited basis. Conversely, the NRG amendment is supported by sound economic theory and will produce a market-based form of compensation which will both fairly compensate existing generators and send the correct price signals.

This concludes our affidavit.

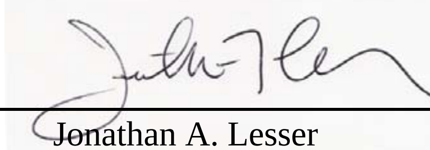
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and New England Power Pool	))	**Docket No. ER08-1209-000**

VERIFICATION

I, Jonathan Lesser, declare under penalty of perjury that the foregoing Affidavit on behalf of the NRG Companies. is true and correct.

Executed this 1st day of August, 2008.



/s/ ______________________________
Jonathan A. Lesser

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and New England Power Pool	))	**Docket No. ER08-1209-000**

VERIFICATION

I, David W. DeRamus declare under penalty of perjury that the foregoing Affidavit on behalf of the NRG Companies. is true and correct.

Executed this 1st day of August, 2008.

/s/ David W. DeRamus
David W. DeRamus

Jonathan A. Lesser, Ph.D.

Partner

Summary of experience

Dr. Jonathan Lesser, a Partner with Bates White, LLC, has 25 years of experience working for regulated utilities, government, and as an economic consultant. He has addressed critical economic and regulatory issues affecting the energy industry, including gas and electric utility structure and operations, mergers and acquisitions, cost allocation and rate design, resource investment decision strategies, cost of capital, depreciation, risk management, incentive regulation, economic impact studies, and general regulatory policy.

Dr. Lesser has designed economic models to value nuclear, fossil fuel, and renewable generating assets, as well as long-term power contracts in the presence of market, regulatory, and environmental uncertainty. He has also actively participated in negotiations for qualifying facilities under PURPA, relicensing of hydroelectric plants, and electric industry market design. Dr. Lesser has prepared expert testimony and reports in cases before utility commissions in numerous states; before the Federal Energy Regulatory Commission (FERC); before international regulators in Belize, Guatemala, Mexico, and Puerto Rico; in commercial litigation cases in Arizona, Vermont, and Washington; and before legislative committees in Connecticut, Maryland, Texas, Vermont, and Washington. He is most recently the coauthor of *Fundamentals of Energy Regulation*, published in 2007 by Public Utilities Reports, Inc., as well as numerous academic and trade press articles, and is a contributing columnist and Editorial Board member for *Natural Gas & Electricity*.

Areas of expertise

- Cost of capital, return on equity, and capital structure
- Cost of service, depreciation, cost allocation, and rate design
- Economic impact analysis
- Environmental compliance strategy
- Commercial damages estimation
- Generating asset valuation
- Market power analysis
- Regulatory policy and market design
- Risk management

Selected expert testimony and reports

Constellation Energy Group

- FERC proceeding (*Maryland Public Utility Commission, et al., v. PJM Interconnection, LLC*, Docket No. EL08-67-000)

  Subject: "Just and reasonableness" of PJM's Reliability Pricing Mechanism.

Government of Belize, Public Utility Commission

- Proceeding before the Belize Public Utility Commission, *In the Matter of the Public Utilities Commission Initial Decision in the 2008 Annual Review Proceeding for Belize Electricity Limited.*

  Subject: Arbitration and Independent Expert's report, in dispute between the Belize PUC and Belize Electricity Limited in an annual electric rate tariff review, as required under Belize law.

Federal Energy Regulatory Commission

- Technical hearings on wholesale electric capacity market design.

  Subject: Analysis of proposal to revise RTO capacity market design developed by the American Forest and Paper Association.

Dogwood Energy, LLC

- Proceeding before the Missouri Public Service Commission, *In the Matter of the Application of Aquila, Inc., d/b/a Aquila Networks - MPS and Aquila Case No. EO-2008-0046, Networks - L&P for Authority to Transfer Operational Control of Certain Transmission Assets to the Midwest Independent Transmission System Operator, Inc.*, Case No. EO-2008-0046.

  Subject: Cost-benefit analysis to determine whether Aquila should join either the Midwest Independent System Operator (MISO) or the Southwest Power Pool (SPP).

Independent Power Producers of New York

- FERC proceeding (*Re: New York Independent System Operator, Inc.*, Docket No. ER08-283-000)

Subject: Revisions to the installed capacity (ICAP) market demand curves in the New York control area, which are designed to provide economic incentives for new generation development.

Empresa Eléctrica de Guatemala

- Rate proceeding before the Comisión Nacional de Energía Eléctrica

  Subject: Weighted average cost of capital.

Electric Power Supply Association

- FERC proceeding (*Re: Midwest Independent Transmission System Operator, Inc.*, Docket No. ER07-1182-000)

  Subject: Critique of cost-benefit analysis by MISO Independent Market Monitor concluding that permanent establishment of Broad Constrained Area mitigation was appropriate.

Constellation Energy Commodities Group, LLC

- FERC rate proceeding regarding rate application for ancillary services by Ameren Energy (*Re: Ameren Energy Marketing Company and Ameren Energy, Inc.*, Docket Nos. ER07-169-000 and ER07-170-000)
- Subject: Analysis and testimony on appropriate "opportunity cost" rates for ancillary services, including regulation service and spinning reserve service. Case settled prior to testimony being filed.

Suiza Dairy Corporation and Vaquería Tres Monjitas, Inc.

- Rate proceeding before the Office of Milk Industry Regulatory Administration of Puerto Rico.
- Subject: Analysis and testimony on the appropriate return on equity for regulated milk processors in the Commonwealth of Puerto Rico.

DPL Inc.

- Proceeding before the Ohio Board of Tax Appeals (*DPL, Inc. and its subsidiaries v. William W. Wilkins, Tax Commissioner of Ohio*, Case No. 2004-A-1437)

Subject: Economic impacts of generation investment and qualification of electric utility investments as "manufacturing" investments for purposes of state investment tax credits.

IGI Resources, LLC and BP Canada Energy Marketing Corp.

- FERC rate proceeding regarding the rate application by Gas Transmission Northwest Corporation (*Re: Gas Transmission Northwest*, Docket No. RP06-407-000)

  Subject: Natural gas supplies, economic lifetime, and depreciation rates.

Baltimore Gas and Electric Co.

- Maryland Public Service Commission (Case No. 9099)

  Subject: Standard Offer Service pricing. Testimony focused on factors driving electric price increases since 1999, and estimates of rates under continued regulation

- Maryland Public Service Commission (Case No. 9073)

  Subject: Stranded costs of generation. Testimony focused on analysis of benefits of competitive wholesale power industry.

- Maryland Public Service Commission (Case No. 9063)

  Subject: Optimal structure of Maryland's electric industry. Testimony focused on the benefits of competitive wholesale electric markets. Presented independent estimates of benefits since 1999.

Pemex-Gas y Petroquímica Básica

- Expert report in a rate proceeding. Presented analysis before the Comisión Reguladora de Energía on the appropriate return on equity.

BP Canada Marketing Corp.

- FERC rate proceeding regarding the rate application by Northern Border Pipeline Company (*Re: Northern Border Pipeline*, Docket No. RP06-072-000)

  Subject: Natural gas supplies, economic lifetime, and depreciation rates.

Transmission Agency of Northern California

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER05-1284-000)

Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket Nos. ER03-409-000, ER03-666-000)

  Subject: Analysis and development of recommendation for the appropriate return on equity, capital structure, and overall cost of capital.

State of New Jersey Board of Public Utilities

- Merger application of Public Service Enterprise Group and Exelon Corporation (*I/M/O The Joint Petition Of Public Service Electric And Gas Company And Exelon Corporation For Approval Of A Change In Control Of Public Service Electric And Gas Company And Related Authorizations, BPU Docket No. EM05020106, OAL Docket No. PUC-1874-050*)

  Subject: Proposed merger between Exelon Corporation and PSEG Corporation. Testimony described the structure and results of a cost-benefit analysis to determine whether the proposed merger met the state's positive benefits test, and included analysis of market power, value of changes in nuclear plant operations, and merger synergies.

Sierra Pacific Power Corp.

- FERC rate proceeding regarding the rate application by Paiute Pipeline Company (*Re Paiute Pipeline Company* Docket No. RP05-163-000)

  Subject: Depreciation analysis, negative salvage, and natural gas supplies. Case settled prior to filing expert testimony.

Matanuska Electric

- Regulatory Commission of Alaska rate proceeding (*In the Matter of the Revision to Current Depreciation Rates Filed by Chugach Electric Association, Inc.*, Docket No. U-04-102)

  Subject: Analysis of the reasonableness of Chugach electric's depreciation study.

Duke Energy North America, LLC

- FERC proceeding (*Re: Devon Power, LLC*, et al., Docket No. ER03-563-030)

  Subject: Appropriate market design for locational installed generating capacity in the New England market to ensure system reliability.

Keyspan-Ravenswood, LLC

- FERC proceeding, *KeySpan-Ravenswood, LLC v. New York Independent System Operator, Inc.*, Docket No. EL05-17-000

  Subject: Estimation of damages arising from a failure by the NYISO to accurately calculate locational installed capacity requirements in New York City during the summer of 2002.

Electric Power Supply Association

- FERC proceeding (*Re: PJM Interconnection, LLC*, Docket No. EL03-236-002)

  Subject: Analysis and critique of proposed pivotal supplier tests for market power in PJM identified load pockets.

Vermont Department of Public Service

- Vermont Public Service Board Rate Proceedings
  - Concurrent proceedings: *Re: Green Mountain Power Corp.*, Dockets No. 7175 and 7176. Subject: Cost of capital and allowed return on equity under cost of service regulation, as well as under a proposed alternative regulation proposal.
  - *Re: Shoreham Telephone Company*, Docket No. 6914. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
  - *Re: Vermont Electric Power Company*, Docket No. 6860. Subject: Development of a least-cost transmission system investment strategy to analyze the prudence of a major high-voltage transmission system upgrade proposed by the Vermont Electric Power Company.
  - *Re: Central Vermont Public Service Company*, Docket No. 6867. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
  - *Re: Green Mountain Power Corporation*, Docket No. 6866. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Pipeline shippers

- FERC rate proceeding (*Re: Northern Natural Gas Company*, Docket No. RP03-398-000)

  Subject: Gas supply analysis to determine pipeline depreciation rates as part of an overall rate proceeding.

Arkansas Oklahoma Gas Corp.

- Oklahoma Corporation Commission rate proceeding (*Re: Arkansas Oklahoma Gas Corporation*, Docket No. 03-088)

  Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

- Arkansas Public Service Commission rate proceedings
  - *In the Matter of the Application of Arkansas Oklahoma Gas Corporation for a General Change in Rates and Tariffs*, Docket No. 05-006-U. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
  - *In the Matter of the Application of Arkansas Oklahoma Gas Corporation for a General Change in Rates and Tariffs*, Docket No. 02-24-U. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Entergy Nuclear Vermont Yankee, LLC

- Vermont Public Service Board proceeding (*Re: Petition of Entergy Nuclear Vermont Yankee for a Certificate of Public Good*, Docket No. 6812)

  Subject: Analysis of the economic benefits of nuclear plant generating capacity expansion as required for an application for a Certificate of Public Good.

Central Illinois Lighting Company

- Illinois Commerce Commission rate proceeding (*Re: Central Illinois Lighting Company*, Docket No. 02-0837)

  Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Citizens Utilities Corp.

- Vermont Public Service Board rate proceeding (*Tariff Filing of Citizens Communications Company requesting a rate increase in the amount of 40.02% to take effect December 15, 2001*, Docket No. 6596)

  Subject: Analysis of the prudence and economic used-and-usefulness of Citizens' long-term purchase of generation from Hydro Quebec, including the estimated environmental costs and benefits of the purchase.

Dynegy LNG Production, LP

- FERC proceeding (*Re: Dynegy LNG Production Terminal, LP*, Docket No. CP01-423-000). September 2001

  Subject: Analysis of market power impacts of proposed LNG facility development.

Missouri Gas Energy Corp.

- FERC proceeding (*Re: Kansas Pipeline Corporation*, Docket No. RP99-485-000)

  Subject: Gas supply analysis to determine pipeline depreciation rates as part of an overall rate proceeding.

Green Mountain Power Corp.

- Vermont Public Service Board rate proceedings
  - *In the Matter of Green Mountain Power Corporation requesting a 12.93% Rate Increase to take effect January 22, 1999*, Docket No. 6107. Subject: Analysis of the appropriate discount rate, treatment of environmental costs, and the treatment of risk and uncertainty as part of a major power-purchase agreement with Hydro-Quebec.
  - *Investigation into the Department of Public Service's Proposed Energy Efficiency Utility*, Docket No. 5980. Subject: Analysis of distributed utility planning methodologies and environmental costs.
  - *Tariff Filing of Green Mountain Power Corporation requesting a 16.7% Rate Increase to take effect 7/31/97*, Docket No. 5983. Subject: Analysis of distributed utility planning methodologies and avoided electricity costs.

- *Tariff Filing of Green Mountain Power Corporation requesting a 16.7% Rate Increase to take effect 7/31/97*, Docket No. 5983. Subject: Valuation of a long-term power purchase contract with Hydro-Quebec in the context of a determination of prudence and economic used-and-usefulness.

United Illuminating Company

- Connecticut Dept. of Public Utility Control proceeding (*Application of the United Illuminating Company for Recovery of Stranded Costs*, Docket No. 99-03-04)

  Subject: Development and application of dynamic programming models to estimate nuclear plant stranded costs.

Other commercial litigation experience

- *IMO Industries v. Transamerica.* Estimated the appropriate discount rate to use in estimating damages over time associated with a failure of the insurance companies to reimburse asbestos-related damage claims and the resulting losses to the firm's value.
- *John C. Lincoln Hospital v. Maricopa County.* Performed statistical analysis to determine the value of a class of unpaid hospital claims.
- *Catamount/Brownell, LLC. v. Randy Rowland.* Prepared an expert report on the damages associated with breach of commercial lease.
- *Lyubner v. Sizzling Platters, Inc.*. Performed an econometric analysis of damage claims based on sales impacts associated with advertising.
- *Pietro v. Pietro*. Estimated pension benefits arising from a divorce case.
- *Nat'l. Association of Electric Manufacturers v. Sorrell.* Testified on the costs of labeling fluorescent lamps and the impacts of labeling laws on the demand for electricity.

Selected business consulting experience

- Faculty member, 24th PURC/World Bank International Training Program on Utility Regulation and Strategy, University of Florida, Public Utility Research Center, Gainesville, FL, June 18, 2008. Courses taught:
  - Sector Issues: Basic Techniques–Energy
  - Sector Issues in Rate Design: Energy
  - Sector Issues in Rate Design: Energy–Case Study
  - Transmission Pricing Issues

- For a major solar energy firm, evaluated costs and benefits of alternative solar technologies; assisted with siting and transmission access issues.
- For Exelon Generation, Inc., prepared reports of the economic benefits of nuclear plant operation and development.
- For the Electric Power Supply Association, prepared numerous policy papers addressing wholesale electric market design and competition.
- For the California Energy Commission, developed a new policy approach to renewables feed-in tariffs and developed portfolio analysis models to develop an "efficient frontier" of generation portfolios for the state.
- For several electric utilities undergoing restructuring, developed complex economic models to value buyer offers associated with nuclear power plant divestitures.
- For a large owner and operator of nuclear generating plants, assessed the likelihood of relicensing a specific nuclear plant in New England, given state regulatory concerns over on-site spent fuel storage.
- For a major New York brokerage firm, performed a fairness opinion valuation of a gas-fired electric generating facility.
- For a large municipal electric utility in Florida, analyzed real option values of alternative proposed purchased generation contracts whose strike prices were tied to future natural gas and oil prices, and developed contract recommendations.
- For a municipal electric utility in Florida, developed an analytical model to determine risk-return tradeoffs of alternative generation portfolios, identify an efficient frontier of generation asset portfolios, and recommended asset purchase and sale strategies.
- For Central Vermont Public Service Corp. and Green Mountain Power Corp., developed analyses of distribution capacity investments accounting for uncertainty over future peak load growth.
- For a major electric utility in Latin America, developed risk management strategies for hedging natural gas supplies with minimal up-front investment; prepared training materials for utility staff; and wrote the utility's risk management Policies and Procedures Manual.
- For a large investor-owned utility in the Southeast, analyzed alternative environmental compliance strategies that directly incorporated uncertainty over future emissions costs, environmental regulations, and alternative pollution control technology effectiveness.

- For a Special Legislative Committee of the Province of New Brunswick, served as an expert advisor on the development of a deregulated electric power market.
- For the Bonneville Power Administration, developed models to assess the economic impacts of local generation resource development in Washington State and Oregon.
- For an electric utility in the Pacific Northwest, assisted in negotiations surrounding relicensing of a large hydroelectric generating facility.
- Served as an expert advisor for the Northwest Power Planning Council regarding future power supplies, load growth, and economic growth.

Education

- Ph.D., Economics, University of Washington
- M.A., Economics, University of Washington
- B.S., Mathematics and Economics (with honors), University of New Mexico

Professional activities

- Reviewer, *Journal of Regulatory Economics*
- Reviewer, *The Energy Journal*

Professional associations

- American Bar Association
- Energy Bar Association
- International Association for Energy Economics

Publications

Peer-reviewed journal articles

- Lesser, J. and X. Su. "Design of an Economically Efficient Feed-in Tariff Structure for Renewable Energy Development." *Energy Policy* 36 (March 2008) 981–990.
- Lesser, J. "The Economic Used-and-Useful Test: Its Origins and Implications for a Restructured Electric Industry." *Energy Law Journal* 23 (November 2002): 349–82.

- Lesser, J., and C. Feinstein. "Electric Utility Restructuring, Regulation of Distribution Utilities, and the Fallacy of 'Avoided Cost' Rules." *Journal of Regulatory Economics* 15 (January 1999): 93–110.
- Lesser, J., and C. Feinstein. "Defining Distributed Utility Planning." *The Energy Journal*, Special Issue, Distributed Resources: Toward a New Paradigm (1998): 41–62.
- Lesser, J., and R. Zerbe. "What Can Economic Analysis Contribute to the Sustainability Debate?" *Contemporary Policy Issues* 13 (July 1995): 88–100.
- Lesser, J., and R. Zerbe. "The Discount Rate for Environmental Projects." *Journal of Policy Analysis and Management* 13 (Winter 1994): 140–56.
- Lesser, J., and D. Dodds. "Can Utility Commissions Improve on Environmental Regulations?" *Land Economics* 70 (February 1994): 63–76.
- Lesser, J. "Estimating the Economic Impacts of Geothermal Resource Development." *Geothermics* 24 (Winter 1994): 52–69.
- Lesser, J. "Application of Stochastic Dominance Tests to Utility Resource Planning Under Uncertainty." *Energy* 15 (December 1990): 949–61.
- Lesser, J. "Resale of the Columbia River Treaty Downstream Power Benefits: One Road From Here to There." *Natural Resources Journal* 30 (July 1990): 609–28.
- Lesser, J., and J. Weber. "The 65 M.P.H. Speed Limit and the Demand for Gasoline: A Case Study for the State of Washington." *Energy Systems and Policy* 13 (July 1989): 191–203.
- Lesser, J. "The Economics of Preference Power." *Research in Law and Economics* 12 (1989): 131–51.

Books and contributed chapters

- Lesser, J., and L.R. Giacchino. *Fundamentals of Energy Regulation*, Vienna, VA: Public Utilities Reports, 2007.
- Lesser, J., and R. Zerbe. "A Practitioner's Guide to Benefit-Cost Analysis." In *Handbook of Public Finance*, edited by F. Thompson, 221–68. New York: Rowan and Allenheld, 1998.
- Lesser, J., D. Dodds, and R. Zerbe. *Environmental Economics and Policy*, Reading: MA: Addison Wesley Longman, 1997.

Trade press publications

- Lesser, J., and N. Puga, "PV versus Solar Thermal," *Public Utilities Fortnightly* 146 (July 2008), pp. 16-20, 27.
- Lesser, J., "Cap-and-Trade for Gasoline?," *Wall Street Journal*, June 14, 2008, A14.
- Lesser, J., "Kansas Secretary Unilaterally Bans Coal Plants," *Natural Gas & Electricity* (June 2008): 30-32.
- Lesser, J., "Seeing Through a Glass, Darkly, Banks Approach Coal-Fired Power Financing," *Natural Gas & Electricity* (April 2008): 29-31.
- Lesser, J., "The Energy Independence and Security Act of 2007: No Subsidy Left Behind," *Natural Gas & Electricity* (February 2008): 29-31.
- Lesser, J. "Control of Greenhouse Gases: Difficult with Either Cap-and-Trade or Tax-and-Spend." *Natural Gas & Electricity* (December 2007): 28-31.
- Lesser, J. "Déjà vu All Over Again: The Grass was not Greener Under Utility Regulation." *The Electricity Journal* 20 (December 2007): 35–39.
- Lesser, J. "Blowin' in the Wind: Renewable Energy Mandates, Electric Rates, and Environmental Quality." *Natural Gas & Electricity* (October 2007): 26-28.
- Lesser, J. "No Leg to Stand On." *Natural Gas & Electricity* (August 2007): 28–31.
- Lesser, J. "Goldilocks Chills Out." *Natural Gas & Electricity* (July 2007): 26–28.
- Lesser, J. "Goldilocks and the Three Climates." *Natural Gas & Electricity* (April 2007): 22–24.
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- Lesser, J. "An Economically Rational Approach to Least-Cost Planning: Comment." *The Electricity Journal* 4 (October 1991).
- Lesser, J., and J. Weber "Energy Efficiency in New Zealand: Issues and Appropriate Institutions for the Electricity Sector." Report to the New Zealand Ministry of the Environment, June 1992.
- Lesser, J. "Long-Term Utility Planning Under Uncertainty: A New Approach." Paper presented for the Electric Power Research Institute: *Innovations in Pricing and Planning*, May 1990.

- Lesser, J. "Centralized vs. Decentralized Resource Acquisition: Implications for Bidding Strategies." *Public Utilities Fortnightly* (June 1990).
- Lesser, J. "Most Value—The Right Measure for the Wrong Market?" *The Electricity Journal* 2 (December 1989): 47–51.
- Lesser, J., et al. "Global Warming: Implications for Energy Policy." Washington State Energy Office, Energy Policy and Planning Research Series, July 1989.

Selected speaking engagements

- "Financial Risks Faced by Regulated Utilities: Implications for the Cost of Capital and Ratemaking Policies," Law Seminars International, Las Vegas, NV, February 7, 2008.
- "Alternative Regulatory Structures and Tariff Mechanisms: Practical approaches to providing low-cost, environmentally responsible energy and how to avoid some dangerous pitfalls." Western Energy Institute, October 1, 2007.
- "Economics and Energy Regulation." Law Seminars International, Washington, DC, March 15-16, 2007.
- "Energy in the Northeast: Resource Adequacy & Reliability." Law Seminars International, Boston, MA, October 16–17, 2006.
- "Energy in the Southwest: New Directions in Energy Markets and Regulations." Law Seminars International, Santa Fe, NM, July 14, 2006.
- "Energy and the Environment." Vermont Journal of Environmental Law, South Royalton, VT, March 10, 2006.
- "Electricity and Natural Gas Regulation: An Introduction." Law Seminars International, Washington, DC, March 17–18, 2005.

David W. DeRamus, Ph.D.

Partner

Summary of experience

David W. DeRamus, Ph.D. is a Partner and founding member of Bates White, LLC and is the Partner in charge of the firm's Energy practice. Dr. DeRamus specializes in economic and financial analysis, quantitative modeling, antitrust analysis, pricing analysis, product liability forecasting, and valuation. Dr. DeRamus has an extensive background in industrial organization, international economics, antitrust economics, microeconomics, finance, financial modeling, and statistical analysis.

Areas of expertise

- Energy
- Antitrust and market power analysis
- Economic and financial analysis
- Econometric and microsimulation modeling
- Pricing analysis

Selected litigation experience

- Submitted testimony on behalf of Milford Power Company, LLC in FERC proceedings (Docket No. ER99-4102-___) related to the Commission's generation market power screens as applicable to Milford's market-based rate authority.
- Testified on behalf of the New York Power Authority in FERC proceedings (Docket No. ER06-456-000, et al.) related to the proposal by PJM Interconnection, L.L.C. to allocate cost responsibility for certain transmission network upgrades included in the baseline PJM Regional Transmission Expansion Plan to merchant transmission projects that interconnect with the PJM transmission network.
- Submitted testimony on behalf of Southaven Power LLC and Kelson Energy III LLC in FERC proceedings (Docket No. EC08-___-000) related to potential market power issues arising from Kelson's proposed acquisition of the Southaven electric generation facility.

Submitted testimony on behalf of Kelson Energy III LLC in FERC Docket No. ER08-___-000 related to the Commission's generation market power screens as applicable to Kelson's application for market-based rate authority.

- Submitted comments in proceedings before the Federal Energy Regulatory Commission (FERC) (Docket Nos. RM07-19-000 and AD07-7-000) related to "Wholesale Competition in Regions with Organized Electric Markets" (*see* "Comments of the Electric Power Supply Association"). Analyzed economic issues related to FERC's demand response proposals.
- Testified on behalf of Tenaska and Coral Power in proceedings before the Public Utility Commission of Texas (PUC Docket No. 33687) related to the application by Entergy Gulf States, Inc. of its "Transition to Competition Plan." Analyzed issues related to Entergy's business strategy, cost-benefit analysis, cost allocation, cross-subsidization, and potential harm to competition.
- Testified on behalf of Shell Trading Gas and Power Company and Calpine Corp. in proceedings before the Federal Energy Regulatory Commission (FERC) (Docket No. ER97-4166-015, EL04-124-000, et al.) related to the application by the Southern Companies (Southern Company Energy Marketing, Inc. and Southern Company Services, Inc.) for market based rate authority. Analyzed issues related to the appropriate implementation of the Commission's Delivered Price Test, generation market power, Southern Companies' transmission network, barriers to entry, and affiliate preferences.
- Submitted testimony on behalf of Constellation Energy Commodities Group, Inc. in a complaint proceeding before FERC (Docket No. EL07-47-000) brought by the Illinois Attorney General against various participants in the Illinois Auction for electric power supplies (held in September 2006). Analyzed issues related to the competitiveness of the auction structure, market concentration, the ability of the participants to exercise market power, and allegations of collusion.
- Submitted testimony on behalf of Occidental Chemical Company in FERC proceedings (Docket No. EC07-70-000) evaluating the proposed acquisition of jurisdictional assets of Calcasieu Power, LLC by Entergy Gulf States, Inc. Analyzed issues related to the impact of the acquisition on market concentration and the ability of the applicant to exercise market power.
- Testified on behalf of the Texas Industrial Energy Consumers in proceedings before the Public Utility Commission of Texas (SOAH Docket No. 473-06-2536 and PUC Docket No. 32766) related to the retail electric power rates charged by Southwestern Public

Service Company. Analyzed issues associated with the appropriate allocation of average system fuel costs and cross-subsidization.

- Testified on behalf of BP Canada Energy Marketing Corp. and IGI Resources, Corp. in FERC proceedings (Docket No. RP06-407) related to the application by Gas Transmission Northwest Corporation for market-based rate authority and flexible services rates for certain transportation services provided by the GTN natural gas pipeline.
- Served as consulting expert on behalf of multiple defendants in several large cases related to the natural gas industry.
- Testified on behalf of Occidental Permian Ltd. and Occidental Power Marketing, L.P. in FERC proceedings (Docket No. EL05-19-002 and ER05-168-001) related to the wholesale electric power rates charged by Southwestern Public Service Company. Analyzed issues associated with the appropriate allocation of average system fuel costs and cross-subsidization.
- Submitted testimony on behalf of Occidental Permian Ltd. and Occidental Power Marketing, L.P. in FERC proceedings (Docket No. ER01-205-009, et al.) related to the application by Southwestern Public Service Company for market-based rate authority. Analyzed issues related to generation market power and affiliate abuse.
- Submitted testimony on behalf of Calpine Corp. in FERC proceedings (Docket No. ER05-1065-000) and testified in Louisiana Public Service Commission proceedings (Docket No. U-28155) related to the application by Entergy Services, Inc., Entergy Louisiana, Inc., and Entergy Gulf States, Inc. to establish an Independent Coordinator of Transmission in the Entergy control area. Analyzed issues related to the functions to be performed by the ICT, Entergy's transmission pricing proposal, and its Weekly Procurement Process proposal.
- Submitted testimony on behalf of Calpine Corp. in proceedings before the Louisiana Public Service Commission (Docket No. U-27836) related to the application by Entergy Louisiana, Inc. and Entergy Gulf States, Inc. for approval of the purchase of the Perryville, La. electric generating facility. Analyzed issues of market power and calculated the extent to which the proposed transaction increased market concentration.
- Submitted testimony on behalf of Calpine Corp. and Occidental Chemical Corp. in FERC proceedings (Docket No. ER91-569-023) related to the application by Entergy Services, Inc. for market based rate authority. Analyzed issues of generation market power, transmission market power, barriers to entry, and affiliate abuse in the Entergy

control area. Implemented a model of the Entergy control area transmission constraints in performing the generation market power analysis.

- Submitted testimony on behalf of Calpine Corp. in FERC proceedings (Docket No. ER96-2495-018, *et al.*) related to the application by AEP Power Marketing, Inc., *et al.* for market based rate authority. Analyzed issues of generation market power, transmission market power, barriers to entry, and affiliate abuse in the AEP-SPP control area.
- Submitted expert testimony on behalf of InterGen in FERC proceedings (Docket No. EC03-131-000) related to Oklahoma Gas & Electric's proposed acquisition of NRG McClain. Analyzed issues of horizontal and vertical market power within the context of a hearing to identify appropriate mitigation measures.
- Submitted expert testimony on behalf of the Independent Energy Producers Association on vertical market power in FERC proceedings (Docket No. ER04-316-000) related to Southern California Edison's proposed acquisition of a Mountainview, Calif., electricity generating facility and a subsequent interaffiliate Power Purchase Agreement.
- Submitted expert testimony on behalf of Duke Energy in FERC proceedings (Docket Nos. EL00-95-075 and EL00-98-063) related to the California power markets during 2000–2001 and allegations of improper bidding behavior. Analyzed detailed data on individual bids and plant-level generation, performed statistical analysis of "physical" and "economic" capacity withholding, analyzed financial market data, examined alleged evidence of manipulative trading strategies, and assessed evidence of coordinated behavior.
- Submitted expert testimony on behalf of Duke Energy in response to a FERC Show Cause Order (Docket No. EL03-152-000) relating to alleged "gaming" behavior in the California power markets.
- Submitted expert testimony assessing the damages resulting from defamation in the travel retail industry.
- Testified in Delaware Chancery Court in a merger-related dispute in the energy industry. Testimony involved the valuation of a potential environmental liability/toxic tort arising from oil and gas operations, including an assessment of the materiality of the liability to the proposed merger.
- Submitted expert testimony in a major price-fixing case involving feed additives on behalf of direct action opt-out plaintiffs. Issues include establishment of liability, estimation of damages, analysis of industry structure, analysis of financial performance, and other pricing-related issues.

- Provided economic analyses related to antitrust issues involving the electric utility industry. Analyzed prices, load patterns, capacity issues, outages, bidding patterns, and allegations of anticompetitive behavior.
- Served as consulting expert on behalf of plaintiffs for monopolization cases involving the computer software industry. Assisted with the development of overall case strategy and preparation of economic analysis used in legal filings, analyzed software pricing issues, investigated and reviewed allegations of anticompetitive behavior, prepared damage estimates, submitted damage reports to clients, and assisted with settlement negotiations.
- Served as consulting expert for several other major antitrust cases, providing economic and financial analyses relevant to both the establishment of liability and the estimation of damages.
- Provided consulting expert services in a major government contract dispute. Assessed the economics of a development contract with defense aerospace companies. Analyzed the contractors' financial performance, financial viability, bankruptcy risks, potential financing sources, project cash-flows, and the impact of contract termination.
- Submitted expert testimony in government procurement litigation matter involving office productivity software. Analyzed financial costs and benefits of software standardization initiative, reviewed product comparisons, analyzed data on software installation and use, evaluated claims regarding alleged product integration and standardization advantages, and analyzed anticompetitive consequences of government procurement decisions.
- Developed a state-of-the-art microsimulation model for estimating the future liability of former asbestos manufacturers from personal injury lawsuits. Developed several financial cash-flow models to determine long-term viability of product liability settlement trusts.
- Conducted several valuation studies related to potential future product liability and potential future litigation recoveries. Valuation reports prepared and submitted as part of the acquisition process for due diligence and tax reporting purposes.
- Conducted a valuation of a plaintiff's legal claims related to several ongoing major litigation matters. Valuation report submitted for tax reporting purposes.
- In a major tax dispute, analyzed the impact of a private-label credit card on a large retailer's sales and profits. Developed a robust statistical model using the company's

point-of-sale data, credit card data, and customer demographic information. Tax dispute resolved in favor of the client based on this analysis.

- In a contract dispute, developed an analysis of bilateral monopoly power used to estimate damages.
- Conducted an anti-dumping study to estimate exposure to tariffs in the petrochemical industry.
- Conducted market and industry analyses for various due diligence, breach of contract, bankruptcy, and product liability engagements in the areas of insurance, general aviation, commercial property, electronic funds transfer, restaurant franchising, and construction.

Selected business consulting experience

- On behalf of the Electric Power Supply Association, analyzed economic issues with respect to demand response programs and price caps in organized electric markets in FERC Docket Nos. RM07-19-000 and AD07-7-000 ("Wholesale Competition in Regions with Organized Electric Markets").
- On behalf of an energy company, prepared a quantitative analysis of the benefits of competitive electric wholesale markets.
- On behalf of an energy company, prepared a whitepaper on the use of competitive procurements as a means of reducing market power in wholesale electric markets.
- In proceedings before the California Public Utilities Commission (Docket No. OIR 01-10-024), submitted report on behalf of the Independent Energy Producers Association regarding the proposed market price referent methodology for use in the California Renewables Portfolio Standards power solicitations.
- Estimated the future asbestos liability of several companies (public and private) for investment research firms and potential acquirers as due diligence. Analyzed the litigation risks faced by the companies, insurance coverage issues, potential consequences of other developments in the asbestos litigation environment, and financial reporting issues.
- Conducted numerous transfer pricing studies for tax planning, documentation, and audits. Clients include large multinational companies involved in automotive manufacturing, medical products, computer software/hardware, industrial equipment, retail clothing, food products, tobacco, oil drilling services, package delivery services, shipping, and industrial products.

- Designed, managed, and implemented intellectual property-related planning initiatives for large multinational clients in manufacturing, computer, telecommunications, and consumer product industries. Designed R&D cost sharing arrangements and prepared transfer pricing documentation for tax compliance.
- Estimated value of liabilities for a remainder trust established for a former manufacturer of food products.
- Managed the development of advanced data analytic software based on artificial neural networks for Internet-based financial services client. Responsible for identifying new product opportunities for client, evaluating feasibility of applications, performing cost-benefit analysis for new product investment, designing implementation plan, and managing the overall software development process.
- In order to determine the appropriate compensation for risk in a long-term supply contract, developed a financial simulation model for a major transportation consortium in contract negotiations with the U.S. Department of Defense.
- Managed and directed various business consulting projects requiring statistical analysis to guide pricing and marketing decisions.
- Provided strategy consulting to seed-stage start-up companies, including development of business strategy, competitive analysis, intellectual property assessment, development of revenue and cost projections, and formulation of business and financing plan.
- Conducted extensive empirical research on the impact of R&D and advertising on profitability; analyzed the impact of foreign exchange rate fluctuations on U.S. prices.

Industry presentations

- COMPETE and the Electric Power Supply Association, Conference, Empowering Customers Through Competitive Markets, November 5, 2007: "Ensuring Consistent Environmental and Competition Policies in Electricity Markets."
- Federal Trade Commission, Conference, Energy Markets in the 21st Century: Competition Policy in Perspective, April 10, 2007: "Empirical Analyses of Wholesale Electric Competition and Industry Restructuring."
- Federal Energy Regulatory Commission, Technical Conference, Generation Market Power and Affiliate Abuse, January 28, 2005: "Comments by David W. DeRamus, Ph.D."

- Federal Energy Regulatory Commission, Technical Conference, Acquisition and Disposition of Merchant Generation Assets by Public Utilities, Docket No. PL04-9-000, June 10, 2004: "Comments by David W. DeRamus, Ph.D."
- Federal Energy Regulatory Commission Technical Conference, Market-Based Rates for Public Utilities, Docket No. RM04-7-000, June 9, 2004: "Comments by David W. DeRamus, Ph.D."
- Electric Power Supply Association, Spring Membership Meeting, April 2004: "Utility Power Supply: Costs and Risks of Vertical Reintegration"
- American Antitrust Institute, Fourth Annual Energy Roundtable Workshop, January 2004: "Electric Utility Reintegration: Vertical Market Power and Potential Market Foreclosure"
- Institute of Public Utilities, Annual Conference, December 2003: "Distinguishing Between Market, Regulatory, and Business Failures"

Professional experience

Dr. DeRamus was previously a Manager with A.T. Kearney and a Senior Manager with KPMG. In both positions, he had broad client responsibility including the management of complex litigation, transfer pricing, and business consulting engagements.

Education

- Ph.D., Economics, University of Massachusetts at Amherst
- M.A., Economics, University of Massachusetts at Amherst
- B.A., Political Science (Magna Cum Laude), Duke University

Professional associations

- American Economic Association
- Energy Bar Association

Languages

- Fluent French and German
- Reading knowledge of Spanish

Related activities and honors

- German Academic Exchange Service Grant (awarded)
- Council for European Studies Pre-Dissertation Fellowship (Columbia University)
- Dean's University Fellowship (University of Massachusetts)
- Herbert Lehman Fellowship (New York State)

De-list Data Submittals Guideline

ISO New England Inc.
Forward Capacity Market
March 30, 2007

Guidelines for De-List Data Submittals

Introduction

This document is a guide for completing the de-list bid cost workbook. The workbook is a part of the de-list bid submittal process, but is not the only component by which the review is conducted. Participants are encouraged to provide any useful additional information to support and supplement the specific information requested in the workbook. Furthermore, during its review of de-list submissions, the ISO may ask for further explanation or substantiation of the information provided. Any such consultation, however, is not intended to relieve the submitter of forwarding any information prior to the qualification deadline.

The format of the workbook captures cost information for each bid on a consistent basis. It is possible additional bid data will be needed given the unique nature of some parameters (outage probability, opportunity costs, for example). These values must be explained, however there are no specific format requirements (no ISO 'form' required). Likewise, for de-list bids representing opportunity costs the values used to derive the de-list bid must be substantiated; but there are no specific format requirements (no ISO 'form' required).

Description

The de-list bid cost workbook consists of three (3) worksheets; a general data sheet, an avoided cost sheet, and a summary sheet. The user is to enter data in the green shaded cells. General information related to the resource is entered on the GENERAL DATA worksheet. All cost information, including adjustments, is entered on the AVOIDABLE COSTS worksheet. All calculations using entered data are done on the SUMMARY worksheet.

The user first enters the plant or resource specific costs on the appropriate worksheet. If plant data (a multi-resource site) is used, a portion of that total should be subsequently prorated to the particular resource. If plant data is prorated, the basis and reasoning for that particular basis should be specified. An entire plant's costs should not be included in a single resource's de-list bid. Only the portion of costs that can be reasonably allocated to the resource, and in particular costs that might otherwise be avoided if the resource were not subject to the obligations of a listed resource, will be considered.

From the resource-specific cost data the workbook calculates the Going-Forward Costs (GFC) and Production Costs terms based on percentage allocations. It is not a requirement that the sum of the Going-Forward Costs and Production Costs allocation amounts equal 100%, but in no case should the total exceed 100%.

The GFC term is intended to capture costs that might be avoided, and that do not vary with the resource's operation. The GFC allocation amounts are intended to reflect the expected avoided costs associated with the capacity attempting to de-list.

The Production Cost term is intended to capture costs that vary with the resource's operation. An example of this type of cost would be a resource that has quantified expected maintenance expenditures in terms of resource operation, or has a maintenance contract that specifies maintenance expenditures in terms of resource operation ($ per start, $/hr or $/MWh). Expenditures so specified would be allocated to Production Costs.

To the extent possible, all costs are to be actual expenses incurred in the most recent full Capability Year (the sample Capability Year). The workbook facilitates a systematic reporting of cost data and tabulates inputs considered in the Internal Market Monitoring Unit review as described in Market Rule 1- Section III.13.1.2.3.2.1.2.

General Data

General Information

- Lead Participant Name and Customer ID
- Contact information (Name, address, telephone number, email address, etc.)
- Resource Name and Asset ID
- Auction Capability Year
- Total Qualified Capacity for auction Capability Year
- Capacity seeking to de-list in auction Capability Year
- CONE price used in auction Capability Year

Historical Information

- Energy (MWh) produced by resource in sample Capability Year

- Total service hours of resource in sample Capability Year

- Equivalent Forced Outage Rate demand (EFORd)
  This value for the resource shall be commensurate with the sample Capability Year and the accuracy and completeness of the EFORd value is related to the accuracy and completeness of the GADS data submitted to the ISO. The ISO may request that the GADS data be explained or substantiated in further detail during the review process.

- Annual Peak Energy Rent (PER) rate
  Until actual PER deductions from Forward Capacity Auction (FCA) payments are recorded, this value will be estimated using historical fuel and energy price data and calculations emulating the settlement calculations of the PER deduction. This value will be a rate ($/kw-yr) and applied to the capacity (kw) attempting to de-list.

  NOTE: The Lead Market Participant may alternatively specify that two select years be used to calculated the PER rate, provided that those same two years be used in determining the RPC rate and inframarginal revenues (ISO revenues minus reported production costs).

- Replacement Cost (RPC) rate
  This value is determined by first summing for every hour in a Capability Year the amount by which the resource's nodal hourly real-time price exceeded the PER Proxy Unit's daily price. The RPC rate is then the average of the most recent three Capability Year sums. This value will be a rate ($/kw-yr) and applied to the capacity (kw) attempting to de-list.

  NOTE: The Lead Market Participant may alternatively specify that only two select years of the three years used to calculate the RPC rate be considered, provided that those same two years be used in determining the PER rate and inframarginal revenues (ISO revenues minus reported production costs).

- ISO Revenues attributable to the resource for sample Capability Year.
  Revenues are to be only ISO market revenues for the resource. Bilateral contracts are not considered.

  NOTE: The Lead Market Participant may alternatively specify that two select years be used to calculate ISO Revenues, provided that those same two years are used in determining the PER rate and RPC rate.

Other Inputs

- Probably estimate of significant decrease in capacity (P)
  This term is meant to be an estimate of the probability that there will be a significant decrease in the resource's capability as specified in Market Rule 1, Section III.13.6.1.1.4, occurring after the de-list bid submittal and before the last annual reconfiguration auction for the Capability Year auctioned. This estimate should be no greater than the EFORd of the resource for the corresponding sample Capability Year and in no case greater than 0.40. An explanation of the derivation of this estimate should be provided.

- 1-Year Constant Maturity Treasury Rate (CMT)
  The most recent reported 1-Year Constant Maturity Treasury Rate at the beginning of the qualification period.

Avoidable Costs

Column A – Description

Operating Expenses

For the sample Capability Year this section details the actual costs incurred associated with staffing and managing the resource in a constant condition of being able to respond to commitment and dispatch orders. Expenses associated with the actual production of energy in the sample Capability Year are also to be included in this section. For sites or resources that have contracts with non-affiliates for operations services, in whole or in part, the terms of the contract should be the basis for related costs included. An entire multi-resource site's costs should not be included in a single resource's de-list bid. Only the portions of costs that can be reasonably allocated to the resource, and in particular costs that might otherwise be avoided if the resource were not subject to the obligations of a listed resource, are to be included.

The prepared expense categories and descriptions are listed below. Expense items not covered by these categories, or items needing specific attention, can be added in the extra lines provided.

- Fuel – Actual cost of fuel(s), including transportation and taxes, if any, consumed in the production of energy.
- Fuel Handling – Fuel handling expenses actually incurred (from unloading to burner).
- Emissions – Actual cost of emission credits used, if any, to comply with all state and federal environmental standards.
- Make-Up Water Treatment – Operating expenses related to the production of water for steam production, if any.
- Cooling System – Operating expenses related to auxiliary cooling systems, if any.
- Waste Water Treatment – Operating expenses related to waste water treatment and disposal, if any.
- Chemicals – Cost of miscellaneous chemicals, if any.
- Consumables – Cost of miscellaneous consumables, if any. Examples: lubricants, grease, rags, packing materials, etc.
- Utilities – Costs related to ancillary heating, cooling, etc.
- Labor – All company employee operating labor expenses (including related payroll taxes, insurance, workman's compensation, etc.).
- Contract Services – Expenses and costs related to plant operating services provided under contract (non-employee), if any.
- Lab Expenses – Expenses associated with routine testing (water, fuel, etc.).
- Environmental – Annual operating expenses related to maintaining compliance with site operating permit and environmental regulations.
- Licenses, Permits, Fees – Annual operating expenses for any licenses, permits and fees necessary for plant operation.

Maintenance Expenses

This section details the actual costs incurred associated with maintaining the resource in good working order in the sample Capability Year. Capital improvement costs are typically considered an opportunity cost and therefore are not intended to be included here. For example, capital costs and expenses associated with major repairs to restore decreases in capacity, or to maintain compliance with the resource's operating permit should not be included here, but instead quantified as an opportunity cost.

Major planned maintenance expenditures (excluding capital) that do not occur annually are intended to be included as an adjustment. Additional expenses quantified as part of a major planned outage should be prorated over the number of years between such outages, and then included as an adjustment. If the major planned outage occurred in the sample capability year, an adjustment would be needed to reduce the expenditure to an amount commensurate with the sum of an average annual major planned maintenance expense and the annual prorated major maintenance expense.

For sites or resources that have contracts with non-affiliates for operations services, in whole or in part, the terms of the contract should be the basis for related costs included here. To the extent maintenance expenses are quantified in terms of the resource's operation or are incurred on the basis of operation, those expenses are to be allocated to production costs ($ per start, $/hour of operation, $/MWh produced). An entire multi-resource site's costs should not be included in a single resource's de-list bid. Furthermore, only the portion of costs that can be reasonably allocated to the resource, and in particular costs that might otherwise be avoided if the resource were not subject to the obligations of a listed resource, are to be considered.

The prepared expense categories and descriptions are listed below. Expense items not covered by these categories, or items needing specific attention, can be added in the extra lines provided.

- Labor – All company employee maintenance labor expenses (including related payroll taxes, insurance, workman's compensation, etc.).
- Contract Services – Expenses and costs related to plant maintenance services provided under contract (non-employee), if any.
- Turbine/Generator – Maintenance expenses related to turbine/generator(s).
- Steam Generator – Maintenance expenses related to steam production equipment, if any.
- Fuel Systems – Maintenance expenses related to fuel storage and handing system equipment.
- Balance of Plant – Maintenance expenses for all other equipment. Examples: switchgear, instrument & control equipment, make-up water/cooling/waste water equipment, emission or environmental control equipment.
- Miscellaneous Maintenance Expenses – Maintenance expenses for all other necessary miscellaneous maintenance tasks. Examples: equipment rental, tool and spare parts replenishment, equipment rental, and other minor consumables.
- Utilities – Costs related to ancillary heating, cooling, etc., not included elsewhere.

Administrative & General

This section details the actual costs incurred associated with overall administration and management of the resource in the sample Capability Year (costs not typically considered Operating or Maintenance costs). For sites or resources that have contracts with non-affiliates for services, in whole or in-part, the terms of the contract should be the basis for related costs included. An entire multi-resource site's costs should not be included in a single resource's de-list bid. Furthermore, only the portion of costs that can be reasonably allocated to the resource, and in particular costs that might otherwise be avoided if the resource were not subject to the obligations of a listed resource, are to be considered.

The prepared expense categories and descriptions are listed below. Expense items not covered by these categories, or items needing specific attention, can be added in the extra lines provided.

- Labor – All company employee administrative labor expenses (including related payroll taxes, insurance, workman's compensation, etc.). Examples: accounting, human resources, legal, etc.
- Office Equipment - Miscellaneous office equipment and supply expenses. Examples: communications equipment, office equipment and supplies, etc.
- Utilities – Expenses associated with ancillary heating, cooling, etc., not included elsewhere.
- Training – Cost of employee training programs, seminars, conferences, etc.
- Information Technology – Expenses associated with computers and equipment, including support costs (employee or contracted), used for resource/site administration and management.
- Safety and First Aid – Expenses associated with safety equipment and services.

Column B – Total Plant Historical Amounts

This column is to contain data representing actual expenses incurred in the sample Capability Year for the total plant. For single resource sites this column may be disregarded and the actual expense data entered into Column (C).

Column C – Unit Historical Amounts

This column is to contain data representing actual expenses incurred in the sample Capability Year for the capacity resource. For multi-resource sites, the data in this column will be the allocated portion of the costs reported in Column (B). For items that are allocated, the basis used for each is to be explained in Column (J) - Comments/Explanations (per MW, per MWh, per unit, etc.).

Column D – Adjustments

This column is to contain adjustments for costs that are not reflected in the cost data in Column (C), but that would or are likely to be incurred in the auction Capability Year. Such adjustments may be included, provided the costs are based on known and measurable conditions. Supplemental data should be included explaining each adjustment. Adjustments for inflation are not to be included.

Column E – As Adjusted

This column is a summation of columns (C) and (D).

Column F – GFC Allowances

This column specifies what percentage of each item in Column (E) is avoidable, independent of actual resource operation. Items are considered avoidable if the costs could be avoided if the resource were not subject to the obligations of a listed resource.

For example, for a resource seeking to fully de-list, the labor cost might be nearly completely avoidable. In this case, the allocation is near 100% as labor costs do not typically vary with resource operation; meaning the labor cost is the same whether the resource is off, on-line at minimum output or at full output. However, if the resource were only seeking to partially de-list, the allocation would be much less, perhaps near zero as the labor required to operate the resource would be unaffected.

NOTE: It is not a requirement that the sum of the Going-Forward Cost and Production Cost allocation amounts equal 100%, but in no case should the total exceed 100%. For sums greater than 100% both allocation values will be highlighted in a bold red font.

Column G – GFC

This column is the product of Column (E) and Column (F).

Column H – Production Cost Allowance

This column specifies what percentage of each item in Column (E) is a direct result of resource operation (including start-up and shut-down costs). These costs are expenses actually incurred when the resource is operated

For example, consider a resource with a maintenance contract specifying $100 of maintenance expense for every hour of service. In this case, a portion of the corresponding total maintenance expense, equal to the product of the contract rate and the total service hours in the sample Capability Year, would be allocated to production costs.

NOTE: It is not a requirement that the sum of the Going-Forward Cost and Production Cost allocation amounts equal 100%, but in no case should the total exceed 100%. For sums greater than 100% both allocation values will be highlighted in a bold red font.

Column I – Production Cost

This column is the product of Column (E) and Column (H).

Column J – Comments/Explanations

Any comments or brief explanations may be entered in this column. Comments may include references to the location of further specific information.

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, DC this 1st day of August, 2008.

/s/ Bethany B. Dukes (e-filed)
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