STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on April 23, 2008

COMMISSIONERS PRESENT:

Garry A. Brown, Chairman
Patricia L. Acampora
Maureen F. Harris
Robert E. Curry, Jr.
Cheryl A. Buley

CASE 07–E-1507 - Proceeding to Establish a Long-Range Electric Resource Plan and Infrastructure Planning Process.

POLICY STATEMENT ON BACKSTOP PROJECT COST RECOVERY AND ALLOCATION

(Issued and Effective April 24, 2008)

BY THE COMMISSION:

INTRODUCTION

On December 24, 2007, we issued our Order Initiating Electricity Reliability and Infrastructure Planning (December Order). Based on concerns that action by the Commission may be required in the near future and on short notice to review, approve, and site a New York Independent System Operator (NYISO) triggered regulated reliability backstop project,[1] we directed that the proceeding first address critical issues associated with such projects.[2]

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[1] As used in this Policy Statement, references to regulated backstop projects includes all regulated reliability projects, whether provided by transmission owners or other merchant providers.

[2] The need for additional resources to maintain reliability that is not being met by a viable market-based project triggers a NYISO request to the Transmission Owners to pursue regulated backstop projects. (NYISO OAT Tariff, Att. Y).

The regulated reliability backstop issues were further divided into two groups: cost allocation and recovery for non-transmission projects on which a statement of the Commission's policy would facilitate the NYISO's timely submission of a compliance filing with the Federal Energy Regulatory Commission (FERC) in early June;[3] and, the processes, filing requirements, and other procedures we should adopt to facilitate the review, approval, and siting of backstop projects. Cost recovery and allocation issues are addressed in this Policy Statement and the remaining backstop project issues will be reviewed later this year.[4]

The process followed to present these initial cost allocation and recovery issues[5] resulted in the parties'[6] March 7, 2008 filing of: "All-Parties Report on Initiative One: Cost Allocation and Cost Recovery for Regulated Backstop Solutions Under Public Service Commission Jurisdiction" (Report[7]). The Report contains the recommendations and critiques of the parties who could not otherwise reach consensus on cost recovery or cost allocation policies. On March 12, 2008, oral argument regarding the parties' differences was held in New York City, generating 190 pages of transcript (Tr.).

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[3] December Order, p. 18.

[4] The parties are drafting a proposed backstop project selection process and interim outline in the second phase of the proceeding. Broader issues of long-term planning for the future evolution of the State's electricity infrastructure will be addressed in a third phase report expected in the third quarter of 2009.

[5] Case 07-E-1507, Ruling on Schedule, January 15, 2008.

[6] The parties contributing to the report included Competitive Power Ventures/New Athens Generating Facility (New Athens), Independent Power Producers of New York (IPPNY), Multiple Intervenors (MI), Niagara Mohawk Power Corporation d/b/a National Grid (Grid), the New York Transmission Owners (TOs), Nucor Steel Auburn (Nucor), and the Retail Energy Supply Association/Small Customer Marketer Coalition (RESA/SMC). Staff of the Department (Staff) organized and produced the report, including its own recommendations.

[7] A copy of the Report is attached.

The Report presents four options for cost recovery mechanisms with the main controversy being whether the costs of state jurisdictional non-transmission projects should or can be placed in FERC tariffs, and whether there may be jurisdictional consequences in doing so. The Report also presents three cost allocation mechanisms with the main controversy addressing the fairness of the various methodologies' allocation of costs to upstate versus downstate customers for projects required to maintain overall system reliability.

BACKGROUND

We stated at the outset of the proceeding that the Public Service Commission "would oversee the regulated backstop selection process and . . . review costs associated with non-transmission, regulated backstop solutions to ascertain that the costs were prudently incurred."[8] This process implements our authority to maintain system reliability and to review such costs to ensure that rates are "just and reasonable" (Public Service Law (PSL) §65)[9]. Our role in choosing among proposed regulated reliability backstop projects and reviewing and providing for the collection of their prudent costs is also consistent with the NYISO FERC-approved tariff.[10]

In addressing cost allocation issues we stated our preference that New York's allocation of non-transmission reliability backstop project costs be sufficiently comparable to FERC's allocation of transmission costs to avoid having projects judged or adopted based on a preferred regulatory cost allocation mechanism.[11] Again, our responsibility to ensure just and reasonable rates for electricity service requires us to establish an equitable approach to recovering costs required to maintain the reliability of the electricity grid.

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[8] December Order, p. 17.

[9] Part of that responsibility is to ensure that imprudent costs are not passed on to consumers.

[10] See NYISO OAT Tariff, Attachment Y §§ 7.3, 7.4(d), 8.4(a), and 11(d).

[11] December Order, p. 17.

COST RECOVERY

Before discussing the four cost recovery options presented by the parties, it is important to note an area of general agreement. The Report (pp. 10-11) indicates that the parties generally support the following:

- Before the establishment of the NYISO planning process and the state-wide wholesale competitive market regime, utilities had the sole industry responsibility to propose projects to ensure a reliable bulk electric system. Utilities built projects, or portions of projects, that were within their respective service territories and recovery was usually from the utility’s ratepayers. With the advent of the competitive market, utilities have gotten out of the business of building generating projects, and the concept of “beneficiaries pay” has been adopted at the NYISO and approved by the FERC. Therefore, in the new context we have the situation where the entity that incurs costs to implement a reliability solution might need to have payment flow from customers of a different LSE/utility.

- Under the NYISO’s CRPP, the implementation of a regulated backstop solution by the Responsible TO(s) to address a reliability need identified in the NYISO’s RNA will not be triggered unless the NYISO determines that a timely solution to an identified reliability need will not be met by market-based projects or local TO plans, and that a regulated solution, subject to the issues under consideration in Initiative One of this proceeding, is necessary.

- Under the CRPP, the Responsible TO(s) will provide a regulated backstop solution to address a reliability need identified in the NYISO’s RNA. The regulated backstop solution provided by the Responsible TO(s) may be a transmission, generation and/or demand-based solution, and may provide for implementation directly by the Responsible TO(s) or by other means. Other parties have the opportunity to submit alternative regulated solutions for consideration.

- The PSC has jurisdiction to determine which of the proposed solutions are in the public interest and should be selected to resolve the reliability need.
- While the PSC has broad electric rate authority over the investor-owned utilities, there are several entities such as NYPA, LIPA and some municipal utilities that are not under PSC rate jurisdiction. Therefore, any cost recovery methodology that would require payment from these entities (as beneficiaries) must coordinate recovery among entities that are not solely under PSC jurisdiction.[12]

In addition to the above points, the parties also suggested principles that were not adopted by consensus. The first, is:

- Reasonably-incurred costs for generation and demand-based projects authorized by the PSC will be recoverable.

According to the Report, MI objected to this statement arguing that "reasonably-incurred" should be "prudently-incurred."[13] "Reasonably-incurred" costs, in our view, are prudent by definition, and the suggested amendment is unnecessary.

The Transmission Owners (TOs) would reword the preceding bullet as follows:

> A clearly defined cost recovery mechanism for the recovery of all reasonably-incurred costs for generation and demand-based projects should be authorized by the PSC, including a surcharge mechanism to provide for the pass-through of such costs to retail customers on a current basis.[14]

IPPNY would rewrite the bullet as:

> The financial requirements identified in the proposal for the chosen solution will be recoverable.[15]

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[12] Report, pp. 10-11.

[13] Id., p. 11.

[14] Id.

[15] Id.

Of the options provided, we prefer the initial formulation of the principle. The TOs' language includes a surcharge mechanism which may or may not be appropriate in all circumstances, and IPPNY's language fails to account for costs that are not reasonably incurred (i.e., imprudent costs). Accordingly, we adopt this principle:

- Reasonably-incurred costs for generation and demand-based projects authorized by the PSC will be recoverable.

Finally, SCMC proposes that the following bullet be added:

- The cost recovery mechanism must ensure that the allocation of costs among Load Serving Entities and the recovery of costs in retail distribution rates are instituted in a competitively and nondiscriminatory [sic] to customers regardless of their commodity supplier.[16]

The Report submitted by the parties offers no reason for rejecting the basic principle that regulatory efforts should not, to the extent reasonably possible, interfere with competition in the retail markets. We agree with SCMC that competitively-neutral and nondiscriminatory rates should be instituted regarding the retail cost recovery of regulated reliability backstop projects, and we adopt this approach as our policy.

Cost Recovery Options

The first cost recovery approach addressed in the Report (pp. 11-13) is supported by Staff, MI, and the New York Consumer Protection Board (CPB). Under Model 1, backstop project costs would be submitted by the utility (or an alternate developer) to the PSC for recovery authorization. A master contract is contemplated between the developer and the beneficiaries, whether those beneficiaries are customers of the traditional utilities, municipalities, or authorities. The

[16] Id.

purpose of the master contract is to transfer PSC-specified retail rate funds to the project developer.

Model 1 also discusses how backstop reliability projects would be incorporated into the markets, for example, by allowing above-market costs (necessitated by the failure of a merchant investment to timely address reliability shortfalls) to be recovered outside of the competitive generation market.[17] In addition, Model 1 provides that: retail collections should be done in a nondiscriminatory manner; specific ratemaking will be determined on a case-by-case basis; NYPA and LIPA contributions, as beneficiaries of the project, would be recovered in a separate mechanism; and agreements that would allow this process to proceed will need to be created. As detailed in the Report (pp. 12-13), a number of parties recommended changes to this Model, including: suggested additional details for the master contract with developers; adding specific statements regarding FERC's jurisdiction; challenging the need for a master contract; and criticizing Model 1 for predetermining the specifics of contracts which would better be determined on a case-by-case basis.

Model 2 is supported by the TOs.[18] According to this Model, developers would file their costs with FERC seeking approval for recovery under a NYISO FERC tariff. If the regulated backstop solution is subject to state jurisdiction (i.e., all non-transmission solutions), the project costs would be submitted first to the state regulatory authority. Model 2 is supposed to prevent the recovery of any costs found inappropriate by the State; but the fact remains that cost recovery approval would, after the State's decision, also be requested from FERC. In concept, the developers would agree in advance that they would not request recovery of any costs disapproved by the state. The Model goes on to recommend the

[17] The Renewable Portfolio Standard uses this approach.

[18] Report, p. 13. As a general matter, TOs include the state rate-regulated electric corporations as well as NYPA and LIPA.

development of a reliability facilities charge (RFC) as the basis for the NYISO rate tariff, which would permit the recovery of "the FERC approved revenue requirement."[19]

A number of parties offered suggested changes to and comments regarding Model 2. These included criticism of the excessive detail of the contract proposed in Model 2, and suggested elimination of the agreement that costs in excess of those found reasonable would not be requested of FERC without the PSC's concurrence. Concerns were also raised regarding rate design and double recovery, the assurance of cost recovery for projects that benefit the State Authorities and municipal electricity systems, and potential discrimination in the retail markets.

Model 3 proposed by New Athens suggests that all backstop reliability projects be limited to non-utility developers.[20] Sponsoring utilities, according to this approach, would be limited to entering into contracts with developers for the output of the projects. Again, opposition to Model 3 included concerns about being overly prescriptive regarding the structure and detail of projects and contracts, objections by the utilities to the elimination of their role in generation construction and ownership, and the apparent limitation of the approach to only fixed-price contracts.

Model 4 is proposed by IPPNY and supported by New Athens. Under this Model, the PSC would solicit backstop solutions, developers would be paid a fixed resource adequacy incentive fee, and the project would be required to rely on the market for all other costs. Under Model 4, a specific type of contract would be used (similar to our RPS program) and cost recovery would be through a full pass-through to retail rates in service class-specific delivery charges of the resource adequacy incentive fee. The details of such charges would be determined

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[19] Id., p. 14.

[20] The "utility developers" excluded under this language are the retail PSC rate-regulated electric corporations.

on a case-by-case basis. Model 4 raises many of the same objections offered in response to Model 3.[21]

DISCUSSION

Staff expressed its concern[22] that, if State jurisdictional costs are recovered in a FERC tariff or under a FERC-approved contract (potential characteristics of both Models 2 and 3), FERC and/or the courts may determine that our State jurisdiction has been ceded to FERC. According to the Report, FERC's staff has stated to our Staff that project costs included in FERC tariffs become subject to FERC jurisdiction to the exclusion of the State. Staff cites as an illustration of its point the station-power decision where state jurisdictional station power costs were included in such tariffs, resulting in the loss of state jurisdiction.[23] According to Staff, CPB, and MI, the Model 1 approach retains the Commission's jurisdiction over the costs of jurisdictional projects, whereas all other models run the risk of either ceding that jurisdiction to FERC or unreasonably constraining the options available for backstop projects.[24] Various parties argue to the contrary, suggesting that the jurisdictional concerns are overstated.

FERC Staff's pronouncement regarding the jurisdiction of FERC over tariff rates and the cases cited by Staff support the conclusion that jurisdiction over the recovery of costs related to non-transmission backstop solutions could be jeopardized by Models 2 or 3. The offer to include a State review of costs prior to submitting the costs to FERC may be of little consequence if FERC asserts jurisdiction and substitutes its judgment for ours. Furthermore, the existing NYISO OAT Tariff-Attachment Y §11.0(d) states that "Costs related to

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[21] Report, pp. 28-31.

[22] Id., p. 17-18, Tr., pp. 67-73.

[23] Niagara Mohawk Power Corporation v. FERC, 452 F.3d 822 (D.C. Cir. 2006).

[24] Report, pp. 17-23.

regulated non-transmission reliability projects will be recovered by the Transmission Owners in accordance with the provisions of New York Public Service Law." Models 2 and 3 are not consistent with this existing tariff language.

In our view, we would not be fulfilling our obligations under the New York State Public Service Law were we to concede jurisdiction to FERC over matters of major significance to the State of New York. Accordingly, we adopt as our policy an approach to cost recovery that is consistent with Model 1. We are persuaded by the comments, however, that the details of the financial transactions need not be narrowly defined at this time. The details suggested by Staff under that model appear to represent a reasonable approach, but we are not prepared now to adopt it to the exclusion of all others. It should suffice to observe that mechanisms can and will be developed, often necessarily depending on specific factual circumstances, to allow regulated reliability project costs to be collected in accordance with the Public Service Law in a fair, equitable, and nondiscriminatory manner, and with due consideration of existing competitive markets. We recognize that agreements and/or contracts of various types may be required to accomplish these results, but eliminating options now for how these rate recoveries will be accomplished will only limit our flexibility in the future to address project-specific circumstances.[25]

COST ALLOCATION

The Report indicates that the parties agree on the following general statements:

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[25] As we noted in our March 21, 2008 Order Denying Petitions for Reconsideration or Clarification (p. 5), we have an "...obligation to consider all costs and risks of the construction and operation of generating plants, including the costs and risks to consumers if utilities performed those functions." Fulfilling this obligation should result in a level playing field for any entity which seeks to complete for a regulated backstop project.

- The NYISO ESPWG has drafted principles under-girding an allocation methodology for application to reliability investments in the FERC tariff. Development of the methodology was pursued with the thought that it could be applied to all resources – transmission, generation and demand-based projects – on an equal basis.
- The cost allocation principles have been approved by FERC and are part of the NYISO's tariff; they are presented in Appendix A. It is proposed that the PSC use the NYISO's cost allocation principles for generation and demand-based projects.
- The cost allocation methodology is still the subject of discussions among market participants and has not been the subject of any filing by the NYISO or any ruling by FERC. The TOs' cost allocation methodology is presented in Appendix B. Grid's red-lined version of the TOs' methodology is presented in Appendix C. Support for Grid's modifications appears in Appendix D. Staff recommends, for the reasons expressed below and in Appendix F, the modified cost allocation methodology as presented in Appendix E.
- The cost allocation methodology ultimately approved by the PSC will require calculations based on the Comprehensive Reliability Plan (CRP) base cases. As such, the calculation of the allocation should be performed by the NYISO for projects where recovery is under PSC jurisdiction.
- The NYISO should provide the results of the allocation to the PSC.[26]

As no party has objected to any of the above matters, including the NYISO cost allocation principles,[27] we adopt these principles for reliability backstop projects as the policy of this Commission.

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[26] Report, pp. 5-6.

[27] Id., Appendix A.

Implementing those general principles, however, appears to have been a more difficult task. While the parties generally acknowledge that cost allocations are as much a matter of art as they are science, they nevertheless offer three different methodologies that have significantly different impacts. The first option, denominated "TOs' Cost Allocation Methodology" was previously developed,[28] and it was anticipated by some that consensus had been reached on that methodology.[29] Con Edison Company of New York, Inc. jointly with Orange and Rockland Utilities (Con Edison) and the New York Power Authority (NYPA) defend the TOs' proposal[30] arguing that the methodology is consistent with how the NYISO markets work generally, and specifically in how capacity requirements are implemented.[31]

Grid contends that the TOs' proposal is unjust and unreasonable because it does not ensure a fair, reasoned, and defensible determination of cost responsibility. As MI suggests, the concern with the TOs' proposal is that more costs than would be equitable are allocated to upstate utilities and customers. Grid believes that, at a minimum, the allocation formula should be revised to remove the proposed credits for Locational Capacity Requirements (the "l-LCR" term in the allocation formula),[32] to ensure that the costs of reliability projects are assigned to all loads contributing to the need and benefiting from the solution. Responding to parties who contend that cost allocation is more art than science, Grid contends

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[28] Id., Appendix B.

[29] See, December Order, p. 17 (describing a cost allocation "tentative agreement").

[30] Attachment, Appendix B. For convenience, we will continue to refer to this methodology as the "TO's proposal," but we recognize that it is not supported by all transmission owners.

[31] Report, p. 8.

[32] Locational capacity requirements apply to the New York City and Long Island zones (J and K), which, for reliability purposes, are required to satisfy a certain minimum capacity amount (80% in New York City and 94% in Long Island) from sources within each zone.

that it is not seeking the perfect solution and would consider other approaches that would satisfy the “beneficiary pays” principle.[33]

The third option for consideration is offered by Staff. Staff notes that the NYISO’s tariffed capacity requirements include an LCR credit, consistent with the TO’s proposal; however, Staff contends that the TOs’ proposal is not consistent in all regards with NYISO’s implementation of capacity requirements, because the TOs’ proposal does not include the statewide installed reserve requirement.[34] Accordingly, Staff recommends the incorporation of installed reserve margin requirements as well as Locational Capacity Requirements in order to be consistent with NYISO’s existing allocation of capacity requirements. Staff recommends its approach as a reasonable compromise between the TOs’ proposal and Grid’s, as explained in more detail in the Report, App. F, G.

DISCUSSION

We understand that the NYISO market participants have long discussed the cost allocation methodology for projects needed to maintain system reliability and that there appeared to be a tentative consensus around the TOs’ proposal. The examples of the resulting allocation of costs using the TOs’ methodology, however, strongly suggest that the methodology does not fairly allocate costs.[35] While we recognize that the art of cost allocations suggests that a range of results might be acceptable, the TO’s cost allocations assuming a statewide deficiency assign costs to upstate zones to a greater degree than seems reasonable.[36]

[33] Report, p. 7.

[34] Id., p. 9. Neither the TOs’ nor Grid’s proposal specifically incorporates the 15% installed reserve margin.

[35] Report, App. D, F, G.

[36] Id., App. G.

In a similar fashion, Grid's proposal, which eliminates LCR from the allocation equation, assigns greater costs to downstate zones than seems reasonable.[37] Staff explains[38] that Grid's approach fails to credit reliability additions to downstate LCRs. The result is the overallocation of costs downstate and the underallocation of costs upstate.

Staff contends that only its approach is completely consistent with the allocation of Installed Capacity (ICAP) requirements under NYISO market rules.[39] Staff observes that under NYISO capacity market rules, downstate customers are responsible for 100% of the cost of capacity needed to meet downstate LCRs. This is mirrored in Step 1 of the TOs' cost allocation proposal, to which all parties agree. However, parties disagree over Step 2 of the cost allocation proposal, involving the allocation of costs for remaining statewide solutions. Under NYISO capacity market rules, all customers are responsible for providing capacity equal to (1+IRM) times their peak loads. Downstate customers receive a credit for their downstate LCR capacity; their remaining capacity requirement, equal to (1+IRM-LCR) times their peak loads, can be procured from the statewide market. Staff believes the cost allocation for statewide solutions should be consistent with this formula, since backstop solutions are intended to meet NYISO's statewide capacity requirements in the event the competitive market fails to do so.

For statewide reliability solutions, Staff provides an illustrative comparison of the three approaches[40] including the following:

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[37] Id.

[38] Id., App. F.

[39] Id.

[40] Id., App. G.

Zone	TOs’	Grid’s	Staff’s
A (Buffalo)	14.9%	8.3%	13.4%
F (Albany)	11.8%	6.6%	10.6%
J (NYC)	12.7%	35.2%	17.8%
K (LI)	0.3%	16.4%	4.0%

Because Staff’s approach considers total ICAP requirements (including the installed reserve margin and LCR requirements), and because the allocation of costs for a Statewide reliability solution appear more balanced and equitable under Staff’s approach, we will adopt the Staff methodology as our policy for the allocation of costs for non-transmission, regulated, backstop reliability projects. We will revisit allocation methodologies at the request of the parties if improved methodologies are offered or if changes are required to address any market bias in transmission versus non-transmission cost allocation methodologies.

CONCLUSION

For the reasons set forth above, we are adopting policies to guide the recovery and allocation of costs for non-transmission regulated backstop reliability projects. We urge NYISO to file with FERC, and urge the NYISO participants and other parties to support, sufficiently equivalent cost allocation provisions for transmission projects, such that our choice of the best regulated backstop project to fulfill a reliability need will not be biased by any material difference between state and federal approaches to cost recovery and allocation.

The Commission orders:

1. This proceeding is continued.

By the Commission

JACLYN A. BRILLING
Secretary

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 07-E-1507 – Electric Resource Plan and Infrastructure Planning Process.

ALL-PARTIES REPORT ON INITIATIVE ONE: COST ALLOCATION AND COST RECOVERY FOR REGULATED BACKSTOP SOLUTIONS UNDER PUBLIC SERVICE COMMISSION JURISDICTION

Contributions by:
Competitive Power Ventures/New Athens Generating Facility
Consumer Protection Board
Department of Public Service Staff
Independent Power Producers of New York
Multiple Intervenors
National Grid
New York Transmission Owners
Nucor Steel Auburn
Retail Energy Supply Association/Small Customer Marketer Coalition

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Revised March 17, 2008

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case 07-E-1507 – Electric Resource Plan and Infrastructure Planning Process.

ALL-PARTIES REPORT ON INITIATIVE ONE: COST ALLOCATION AND COST RECOVERY FOR REGULATED BACKSTOP SOLUTIONS UNDER PUBLIC SERVICE COMMISSION JURISDICTION

INTRODUCTION

On December 24, 2007, the New York Public Service Commission (PSC, Commission) issued an order establishing a collaborative structure to develop a long-range planning process to address resource adequacy and electricity infrastructure.[1] The Commission directed the Administrative Law Judge (ALJ) and the parties to focus on two major efforts. First, the Commission asked for a report addressing "the process and decisional standards to be used to approve and construct a regulated backstop project in the near-term." Second, the Commission directed the ALJ and the parties to develop a "long-term (ten to fifteen year), electricity resource plan (ERP) to provide guidance in exercising backstop responsibilities" pertinent to the "long-term energy policies, goals, and needs of New York."

The New York Independent System Operator, Inc. (NYISO) is obligated to make a filing with the Federal Energy Regulatory Commission (FERC) in June 2008 on cost allocation and cost recovery for regulated backstop solutions under FERC jurisdiction. The FERC filing, which was to be made in December 2007, was delayed at the request of the NYISO, the New York Transmission Owners (TOs)[2] and Department of Public Service (DPS) Staff, to permit the PSC time to develop cost allocation and cost recovery mechanisms for reliability solutions subject to PSC jurisdiction comparable to those developed by the NYISO for transmission solutions. The

[1] Case 07-E-1507, supra, Order Initiating Electricity Reliability and Infrastructure Planning (Instituting Order).

[2] The New York TOs are comprised of Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Long Island Power Authority, New York Power Authority, Orange and Rockland Utilities, Inc. and Rochester Gas and Electric Corporation.

ALJ and parties determined that, to allow adequate time for the NYISO to prepare its FERC filing, it is desirable for the Commission to issue an order in April 2008 on cost allocation and cost recovery for regulated backstop solutions under PSC jurisdiction. Accordingly, the first phase of the case was itself divided into two components, the first of which is the subject of this report. The balance of the Phase 1 inquiry is expected to be addressed in a report prepared this summer.

Regarding cost allocation, the parties recommend that the Commission use the same methodology as the NYISO to ensure that cost allocation considerations do not influence the type of regulated backstop solution that may be chosen to address a reliability need for which the market does not respond. Three such methodologies are presented. Regarding cost recovery, this report describes four proposals and discusses the parties' views of their respective attributes and shortcomings.

BACKGROUND

The Instituting Order states that the decision to begin this planning process is based on the Commission's obligations under the Public Service Law (PSL). Noting PSL §§ 5(2) and 65, the Instituting Order states: "The law requires that the Commission, inter alia, ensure safe and adequate service at just and reasonable rates, preserve environmental values, conserve natural resources, encourage long-range programs, and care for the public safety." The NYISO also has certain obligations regarding planning. Attachment Y to the NYISO's Open Access Transmission Tariff (OATT), which was conditionally accepted by FERC on December 28, 2004, implemented the NYISO's Comprehensive Reliability Planning Process (CRPP).[3]

Attachment Y establishes an open and transparent process to identify transmission upgrades, generation additions, and demand side resources needed for reliability reasons. The NYISO is the only ISO/RTO that has a planning process that fully considers all three resources on an equal footing when reliability needs are identified. Transmission, generation, and demand response solutions are not only solicited as market-based responses, but may be submitted as regulated backstop solutions by the Responsible Transmission Owners or as alternate regulated solutions by another TO or a developer.

[3] New York Independent System Operator, Inc., 109 FERC ¶ 61,372 (2004).

Pursuant to the CRPP, a Reliability Needs Assessment (RNA) covering a ten-year planning horizon based upon existing reliability criteria is performed annually. If the NYISO were to determine that resource adequacy may become jeopardized and that no market solution had been proposed that satisfies the identified need, then it would designate one or more TOs as responsible for developing a regulated backstop solution. The TOs have tentatively agreed to assume the responsibility for the development of regulated backstop solutions to meet reliability needs identified in the CRPP on the condition that there are mechanisms in place for the full recovery of their reasonably-incurred costs with respect to all types of regulated solutions. The RNA identifies violations of reliability criteria but does not identify specific facilities to meet the identified need. The NYISO would evaluate any forthcoming proposals for regulated backstop solutions to determine whether they meet the identified reliability need. After this occurs, the process shifts to the Commission. As the Instituting Order remarked (at 17):

> To ensure that an integrated selection process is implemented for regulated backstop projects and the dual jurisdictional duties of the PSC and the FERC are respected, the PSC would oversee the regulated backstop selection process and exercise its authority to review costs associated with the non-transmission, regulated backstop solutions to ascertain that the costs were prudently incurred.

This report discusses cost allocation and cost recovery issues; the regulated backstop selection process will be the subject of a forthcoming report this summer.

The parties agree that the cost allocation methodology that applies to FERC-jurisdictional projects and PSC-jurisdictional projects should be compatible so that the cost allocation method is not a factor in the choice of the preferred solution. It is the parties' preference that the Commission should adopt the same cost allocation method for PSC-jurisdictional projects that the NYISO will file with FERC for FERC-jurisdictional projects.

The question of which projects would be subject to PSC regulation can best be examined through examples.[4]

[4] These examples are for illustrative purposes only. There may be other proposals for regulated backstop solutions that are brought to the Commission for consideration. Additionally, this Report does not seek to bind the Commission, or parties, as to how a regulated backstop solution similar to any of the above examples should be treated.

Example 1: Suppose a utility proposed to build a new plant and requested full cost recovery as well as a rate of return.[5] All risk is placed on ratepayers. The PSC would apply full regulation including any warranted review of prudent costs, determine the proper rate recovery in a filed tariff and arrange for the appropriate cash flow. The utility would be expected to operate the plant in the interest of ratepayers and any market-based revenues would be credited to ratepayers. These same principles would apply to a demand-based project.

Example 2: Suppose an independent generator proposes to build a new plant and requested full cost recovery as well as a rate of return. Just as in Example 1, all risk is placed on ratepayers. The generator would be treated as any other regulated utility by the Commission. The PSC would apply full regulation including any warranted review of prudent costs, determine the proper rate recovery in a PSC-filed tariff for recovery of capital cost and arrange for the appropriate cash flow. The independent generator would be expected to operate the plant in the interest of ratepayers and any market-based revenues would be credited to ratepayers.

Example 3: Suppose a utility executed a long-term contract with an independent generator for energy. This would be a FERC-jurisdictional contract. However, given that the utility has a prudence exposure with the Commission, the utility would present the contract to the PSC for review before executing the contract.

Example 4: Suppose an independent generator proposes to offer a reliability service for a fixed price for a fixed term. In other words, the generator will gain most of its revenues in the market but only requires a relatively small fixed incremental amount to ensure that it continues operation and participates in the NYISO markets. Here ratepayers have a much smaller risk, which would likely warrant some level of lightened regulation for the generator, and the requirements that market-based revenues be returned to the ratepayer would not apply. The PSC would arrange for a cash flow to cover the service.

Example 5: In this example offered by IPPNY, suppose a utility proposes a transmission project as a reliability backstop solution. Here, apart from selection of the preferred reliability backstop solution, the PSC role is limited. According to IPPNY, the costs and method for recovery of the costs of transmission solutions are FERC-jurisdictional. However, DPS Staff notes that the PSC retains rate design flexibility.

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5 Independent Power Producers of New York, Inc. (IPPNY) notes that, for clarification purposes only, the generator is seeking both return of, and on, its costs.

National Grid submits that the statement in Example 4, above ("Here ratepayers have a much smaller risk, which would likely warrant some level of lightened regulation for the generator….") may not be true. For example, if fixed price plus market revenues turn out not to be enough, ratepayers will end up having to pay the difference since the generator is needed for reliability and will not be allowed to shut down. Moreover, National Grid asserts, ratepayers will be paying for all the infra-marginal market revenues the generator is allowed to keep (some of which may be paid at times of scarcity when prices may not best reflect competitively determined market prices). As a result, risk and total costs to ratepayers could be well above a full cost of service contract with a guaranteed rate of return. National Grid questions how all of this would be considered in the evaluation and comparison with other projects (e.g., who will estimate the total cost of market revenues paid by ratepayers and retained by the generator over the life of the project, and who will analyze the risk of the generator-proposed supplemental fixed price payments not being sufficient to fully support the generator over its life?). Finally, this type of contract in this situation is, in effect, a guarantee that the generator will get the higher/better of cost of service or market prices. In National Grid's view, this would not provide the proper incentives to market participants and would severely hamper development of market solutions.

The parties have discussed three approaches to cost recovery, one advanced by Staff, which is supported by Multiple Interveners (MI) and Consumer Protection Board (CPB), a second advanced by the TOs, which includes a modification of the TOs' proposal by National Grid to address formula rates, and a third advanced by Competitive Power Ventures/New Athens Generating Facility LLC (CPV/NAG). Recently, during the drafting process of this document, IPPNY advanced a fourth model, which shares some features of CPV/Nag's model and is supported by CPV/NAG.

COST ALLOCATION

The parties generally agree on basic approaches to this issue:

- The NYISO ESPWG has drafted principles under girding an allocation methodology for application to reliability investments in the FERC tariff. Development of the methodology was pursued with the thought that it could be applied to all resources – transmission, generation and demand-based projects – on an equal basis.

- The cost allocation principles have been approved by FERC and are part of the NYISO's tariff; they are presented in Appendix A. It is proposed that the PSC use the NYISO's cost allocation principles for generation and demand-based projects.

- The cost allocation methodology is still the subject of discussions among market participants and has not been the subject of any filing by the NYISO or any ruling by FERC. The TOs' cost allocation methodology is presented in Appendix B. National Grid's red-lined version of the TOs' methodology is presented in Appendix C. Support for National Grid's modifications appears in Appendix D. Staff recommends, for the reasons expressed below and in Appendix F, the modified cost allocation methodology as presented in Appendix E.

- The cost allocation methodology ultimately approved by the PSC will require calculations based on the Comprehensive Reliability Plan (CRP) base cases. As such, the calculation of the allocation should be performed by the NYISO for projects where recovery is under PSC jurisdiction.

- The NYISO should provide the results of the allocation to the PSC.

National Grid submits that certain aspects of the TOs' cost allocation methodology are unjust and unreasonable and must be revised to ensure that cost responsibility for solutions to statewide reliability deficiencies is determined in a manner consistent with well established and accepted cost causation/beneficiaries pay principles. MI similarly expresses its concern that the TOs' allocation methodology may not be equitable to Upstate customers in instances where there is a statewide reliability need.

National Grid believes that, as a minimum, the proposal for cost allocation should be revised to remove the proposed credits for Locational Capacity Requirements (LCR) from the formulas. As shown in the attached proposed revision of the current cost allocation proposal, National Grid requests that the proposed cost allocation methodology be revised to remove the credits for LCR, shown in the formulas as "1-LCR," in order to ensure that costs of reliability projects implemented under the NYISO CRPP process are assigned justly, as intended, to <u>all</u> loads contributing to the need for and benefiting from the solution.

If there is no LCR deficiency, or at the point after each LCR zone has addressed an existing LCR deficiency and a reliability solution is needed to bring the <u>entire</u> New York Control Area (NYCA) in compliance with reliability criterion, then, states National Grid, <u>all</u> loads must share equally in the responsibility for its costs. Loads in zones with explicit LCR obligations should not be excused from this responsibility. Doing so would require evidence that the other zones (i.e., zones without explicit LCRs) are less reliable, have a greater need, and benefit to a greater extent from the additional capacity still required for the entire control area. Some stakeholders, National Grid argues, seem to miss this point.

While zones with explicit LCRs might pay some higher costs in the NYISO locational capacity markets and/or be allocated costs for regulated reliability solutions that address their LCR deficiencies, this is how it should be, in National Grid's view, since such cost responsibility follows the well-accepted cost causation/beneficiaries pay principles. However, this LCR responsibility alone in no way reduces such zones' responsibility for solutions that might still be required to ensure that the reliability needs of the entire NYCA are satisfied. The well-established cost causation/beneficiaries pay principles must still be followed, according to National Grid. Without reason, National Grid states, the allocation formulas included in the current cost allocation proposal ignore these principles when, in effect, they would penalize load in zones without LCRs, simply because those zones have no such locational requirement, when allocating costs for solutions to statewide reliability needs.

By its proposed revisions, National Grid submits that the cost allocation methodology should be revised to correct this flaw. The allocation of any statewide reliability planning project costs not otherwise allocated to a zone with LCR deficiencies or a zone responsible under the binding interface test should be shared equally among all consumers in the state on a load-ratio-share basis. Moreover, National Grid believes, the cost allocation proposal should make clear that the cost of any solution – regardless of its location – that provides similar reliability benefits as a locally interconnected facility that addresses an LCR deficiency, should be borne by the LCR deficient zone.

Finally, while some stakeholders have dismissed or argued against National Grid's suggested revisions on the basis that cost allocation is more of an art than a science and that there is no "perfect" cost allocation methodology, it is important to understand, it notes, that it is not insisting on the perfect methodology. National Grid states that it is simply seeking the minimal revision necessary to produce a fair, reasoned, and defensible allocation of the costs at issue here. National Grid advises that if stakeholders wish to pursue other methodologies that might be even more consistent with the cost causation/beneficiaries pay principles, then its March 4, 2008, presentation to the NYISO ESPWG (Appendix D) provides other ideas (e.g., an allocation based on zonal loss of load expectations (LOLEs) and their contribution to the NYCA reliability violation).

Con Ed, O&R and NYPA defend the TOs' proposal for cost allocation, explaining that the proposed process includes four steps that first consider locational capacity requirements deficiencies, then Statewide resource deficiencies, then binding interface constraints, and a final step to share costs Statewide should any needs remain that are not met by the first three steps. They continue that, regarding solutions to locational needs, all of those costs are assigned to customers in the location (NYC or LI) in which the needs arises, even though the reliability benefits of implementing such a solution will be realized by all zones across the State. Regarding solutions to statewide needs, Con Ed, O&R and NYPA state that the proposal then allocates the remaining statewide needs in proportion to the locational zones' participation in statewide markets or to the specific zone(s) that cause the remaining need. This, they assert, is consistent with how the NYISO's markets works generally, and specifically in how its capacity requirements are implemented to meet reliability needs. In capacity markets, costs necessary to meet locational reliability requirements are paid for by customers in that locational zone, according to Con Ed, O&R and NYPA, while those same customers also pay a pro-rata share of Rest-of-State (ROS) costs necessary to meet their overall reliability requirements."

Staff offers an example that may help illustrate the difference in cost allocations between the TOs' proposal and National Grid's alternative. In "Examples of Cost Allocation for Reliability Projects 08-13-07," Case 1,[6] the costs of a hypothetical statewide solution were allocated across load zones according to the TOs' proposal. In the example, zone J (NYC) was responsible for 35% of the NYCA peak load, and zone K (LI) was responsible for 16% of the NYCA peak load. However, the TOs' proposal formula multiplies zonal load by the factor (1-LCR), where locational capacity requirement (LCR) is the locational requirement for the zone, i.e. 80% for NYC and 99% for LI.[7] As a result, the formula only counted 20% of zone J's peak

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[6] See ESPWG meeting materials for August 15, 2007, "Cost Allocation for Reliability Projects Clean," pp. 2-3: http://www.nyiso.com/public/webdocs/committees/bic_espwg/meeting_materials/2007-08-15/Cost_Allocation_for_Reliability_Projects_clean.pdf

[7] The LI LCR was recently decreased to 94%. The example uses last year's value of 99%.

load and 1% of zone K's peak load. The net result is that the TOs' proposal allocated just 13% of the costs to zone J and 0.3% to zone K. Under National Grid's alternative, zone J would be allocated 35% of the costs, and zone K would be allocated 16% of the costs, equal to their share of total load.

Con Ed, O&R and NYPA argue that the TOs' proposed cost allocation is consistent with the NYISO's implementation of capacity requirements. However, there is a significant difference between the TOs' proposed allocation of costs and the NYISO's allocation of capacity requirements. The NYISO's capacity requirements include a statewide installed reserve margin (IRM) currently set at 16.5%,[8] meaning that all LSEs are required to procure a minimum amount of installed capacity equal to (1+IRM) times their peak load. The LCR is also a function of peak load; thus LSEs serving zone J (NYC) are required to procure capacity equal to 80% of their peak load from within NYC; the remainder, equal to 36.5% (1+IRM - 80%) times their peak load, can be procured from Upstate. Similarly, LSEs serving zone K (LI) are required to procure capacity equal to 99% of their peak load from within LI; the remainder, equal to 17.5% (1+IRM - 99%) times their peak load, can be procured from Upstate.

Thus, to make the TOs' proposal regarding cost allocation consistent with the NYISO's allocation of capacity requirements, Staff recommends (in Appendix E) that the formula should take into account the IRM as well as the LCRs. In the above example, the formula would be adjusted by replacing the factor (1-LCR) with the factor (1+IRM-LCR). As a result, the adjusted formula would count 36.5% of zone J's peak load and 17.5% of zone K's peak load. The net result is that the adjusted formula would allocate 18% of the costs to zone J and 4% of the costs to zone K.[9] This is the same allocation that would obtain if all installed capacity (equal to the minimum statewide and locational requirements) had been procured under the reliability backstop procedure.

Staff recognizes that cost allocation is not an exact science, but believes that the proposed formula is a reasonable compromise that is consistent with the allocation of minimum capacity requirements. The inclusion of the IRM component also ensures that the allocation factor cannot

[8] The IRM was recently decreased to 15%. The example uses last year's value of 16.5%.

[9] The updated IRM and LCR values slightly change the allocations: The formula would now allocate 17% of the costs to zone J and 5% of the costs to zone K.

be negative, as could have happened with the (1-LCR) factor, since the LCR can be greater than 1 but cannot be greater than (1+IRM). At the hearing held on March 12, 2007, the ALJ asked Staff to explain further the reasoning underlying its cost allocation proposal. In addition to the remarks made orally, Staff has prepared Appendices F and G.

COST RECOVERY

The parties have agreed on these general principles regarding cost recovery:

- Before the establishment of the NYISO planning process and the state-wide wholesale competitive market regime, utilities had the sole industry responsibility to propose projects to ensure a reliable bulk electric system. Utilities built projects, or portions of projects, that were within their respective service territories and recovery was usually from the utility's ratepayers. With the advent of the competitive market, utilities have gotten out of the business of building generating projects, and the concept of "beneficiaries pay" has been adopted at the NYISO and approved by the FERC. Therefore, in the new context we have the situation where the entity that incurs costs to implement a reliability solution might need to have payment flow from customers of a different LSE/utility.

- Under the NYISO's CRPP, the implementation of a regulated backstop solution by the Responsible TO(s) to address a reliability need identified in the NYISO's RNA will not be triggered unless the NYISO determines that a timely solution to an identified reliability need will not be met by market-based projects or local TO plans, and that a regulated solution, subject to the issues under consideration in Initiative One of this proceeding, is necessary.

- Under the CRPP, the Responsible TO(s) will provide a regulated backstop solution to address a reliability need identified in the NYISO's RNA. The regulated backstop solution provided by the Responsible TO(s) may be a transmission, generation and/or demand-based solution, and may provide for implementation directly by the Responsible TO(s) or by other means. Other parties have the opportunity to submit alternative regulated solutions for consideration.

- The PSC has jurisdiction to determine which of the proposed solutions are in the public interest and should be selected to resolve the reliability need.

- While the PSC has broad electric rate authority over the investor-owned utilities, there are several entities such as NYPA, LIPA and some municipal utilities that are not under PSC rate jurisdiction. Therefore, any cost recovery methodology that would require payment from these entities (as beneficiaries) must coordinate recovery among entities that are not solely under PSC jurisdiction.

- Reasonably-incurred[10] costs for generation and demand-based projects authorized by the PSC will be recoverable.

- The TOs would rewrite this last bullet as follows: A clearly defined cost recovery mechanism for the recovery of all reasonably-incurred costs for generation and demand-based projects should be authorized by the PSC, including a surcharge mechanism to provide for the pass through of such costs to retail customers on a current basis.

IPPNY would rewrite the last bullet as follows:

- The financial requirements identified in the proposal for the chosen solution will be recoverable.

Retail Energy Supply Association/Small Customer Marketer Coalition (RESA/SCMC) would add as a bullet:

- The cost recovery mechanism must ensure that the allocation of costs among Load Serving Entities and the recovery of costs in retail distribution rates are instituted in a competitively neutral and non-discriminatory to customers regardless of their commodity supplier.

As noted above, three cost recovery methods have been discussed by the parties and another has just been submitted. It may be useful to keep in mind the examples, presented above, when considering these models.

MODEL 1: PSC-DIRECTED RECOVERY

As proposed by DPS Staff and supported by MI and CPB:

- The investor-owned utility or alternate developer will file generation and demand-based project costs with the PSC for recovery authorization.

- A master contract will be developed between the developer and the Responsible TOs and municipalities that have been designated as beneficiaries in the cost allocation process. This contract is specifically to transfer PSC specified retail ratepayer funds to the project developer (i.e., payment amount and schedule of payments).

[10] MI would use the term "prudently-incurred."

- Incremental Transmission Congestion Contracts (TCCs), installed capacity, energy and/or other products resulting from the reliability project will be auctioned into the appropriate NYISO markets and the resulting revenues will offset a project's revenue requirement for non-fixed price, full-requirements proposals. The purpose of such offsets is to minimize the cost of the regulated backstop solution to customers.

- There will be a mechanism established by the PSC to recover investor-owned utility payments from retail ratepayers in a manner that is non-discriminatory to customers regardless of their commodity supplier. The mechanism will provide a full pass through to retail rates of the investor-owned utility payments through service-class specific delivery surcharges, which need not be volumetric. Ratemaking for the recovery of these costs will be determined on a case-by-case basis.

- NYPA and LIPA costs will be recovered through a separate mechanism.

- NYPA, LIPA and PSC would develop an agreement establishing the conditions under which the Authorities will contract with the project sponsor for recovery of the sponsor's costs. In the event that it is decided not to include LIPA and NYPA's demand-based and generation projects in the NYISO tariff, the converse of the agreement would have to be developed.

IPPNY would change Model 1 by:

- Deleting the phrase "or alternate developer" from the first bullet;
- Including the following bullet between bullets 2 and 3:
  Pursuant to the master contract, developers will be paid a fixed kWh payment for "resource adequacy" as an "incentive" to go forward with their reliability projects. Developers will be required to rely on the market revenues to pay their remaining costs for their projects;[11]
- Deleting bullet 3.

CPV/NAG would change Model 1 by:

- Deleting the first bullet;
- Adding to the second bullet a statement that they consider this contract to be subject to FERC jurisdiction;
- Adding the following as a bullet: Contracts for sale of electricity at wholesale would be subject to FERC filing requirements.

The TOs would change Model 1 by:

- Changing bullet 4 by replacing "ratemaking" with "rate design."

National Grid would change Model 1 by:

[11] Model 4 sets forth IPPNY's proposed structure.

- Regarding bullet 2, National Grid submits that this type of contract should be used only for this purpose and that no other responsibility, obligation or risk is to be put on the Responsible TO(s) or municipalities through such contract. National Grid has concerns over whether any such contract is appropriate or needed, and believes this issue should be considered in Phase II of this proceeding.
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  Further, National Grid disagrees with the changes to Model 1 proposed by IPPNY and CPV/NAG. IPPNY's first change would put the entire burden of proposing generation or demand response projects upon the TOs and eliminate the obligation of any other market participant from fully participating in the planning/CRPP solution process. According to National Grid, IPPNY's second and third proposed changes would not fit with regulated cost recovery, appear to attempt to predetermine the type of contract for recovery, and prevent consideration of full cost of service recovery. National Grid opposes CPV/NAG's proposed changes to the extent they seek to limit the ability of a TO to propose a planning/CRPP solution.

MODEL 2: NYISO – FERC TARIFF

As proposed by the Transmission Owners:

- Prior to the implementation of the preferred transmission or non-transmission regulated solution and any collection of project costs under the NYISO's tariff (or FERC approved formula rate if appropriate), the Responsible TO, other TO or the NYISO as requested by a jurisdictional entity or on behalf of a non-jurisdictional TO or a non-TO developer will make a Section 205 filing with FERC describing the project and its related costs and seeking approval for cost collection under the NYISO tariff.[12] If the preferred solution is subject to state jurisdiction, the project cost will be submitted for review by the appropriate state regulatory authority. In the case of a state jurisdictional project, the project cost recovery sought to be collected under the NYISO tariff would not include any costs that have been found by the appropriate state regulatory authority to have been imprudently incurred, provided that the developer has a legal right to judicial review of the decision of the state regulatory authority.

- The NYISO will assess project costs to its transmission customers, including TOs, municipal systems, state authorities and competitive LSEs, in the zones, and sub-zones,

[12] National Grid's position is that for a TO that has a formula rate filed with FERC defining and allowing recovery of the revenue requirements associated with any costs that include CRPP projects, the TO may recover the project costs in accordance with such FERC-approved formula rate. National Grid and the other TOs are in discussions concerning the recovery of CRPP costs under a formula rate.

to which costs have been allocated under the NYISO's cost allocation methodology, regardless of the nature of the project.

- The project costs will be collected through a separate NYISO rate schedule (e.g., a Reliability Facilities Charge or RFC). The FERC-approved revenue requirement for each backstop project will be the basis for a monthly RFC. The NYISO will adjust the RFC to account for variances in the billing collections to properly equate the revenues received with the FERC approved revenue requirement. In the event that LIPA undertakes a regulated backstop project on Long Island, project costs incurred by LIPA and allocated to customers in LIPA's transmission district will be charged and recovered by LIPA through a separate rate mechanism approved by the LIPA Board. For LIPA project costs allocated to other transmission districts, the NYISO will enter into a cost-sharing agreement with LIPA for the reimbursement of costs incurred by LIPA.

- NYISO market products produced by the reliability project (e.g., TCCs, energy and ancillary services, and installed capacity) will be credits to offset the project's monthly revenue requirement.

- The NYISO will collect the RFC revenues on a monthly basis and remit those revenues to the appropriate TO or other developer.

- There will be a surcharge mechanism established by the Commission to provide a full pass through to retail rates of the investor-owned utility payments. Rate design for the recovery of these costs will be determined on a case by case basis.

- In the case of a state jurisdictional project, a request to revise the FERC-approved rate will not be made without the concurrence of the appropriate state regulatory authority.

IPPNY would change Model 2 by:

- Deleting the following from bullet 1: If the preferred solution is subject to state jurisdiction, the project cost will be submitted for review by the appropriate state regulatory authority. In the case of a state jurisdictional project, the project cost recovery sought to be collected under the NYISO tariff will not include any costs that have been found by the appropriate state regulatory authority to have been imprudently incurred, provided that the developer has a legal right to judicial review of the decision of the state regulatory authority;
- Adding as a first sentence to bullet 1: In the event that a generation alternative is chosen, a contract will be executed;
- Deleting the fourth bullet. IPPNY does not believe that we should limit the structure of the contract at this stage because these issues will more properly and more fully be addressed in the second phase of this proceeding.
- Deleting the last bullet.

CPV/NAG would change Model 2 by:

- Adding the phrase "for provision of backstop reliability service" after the phrase "Section 205 filing with FERC" in bullet 1;
- Making the first and third changes, as suggested by IPPNY.

MI would change Model 2, which it does not support, by:

- Modifying the sixth bullet to provide that: (a) any retail rate recovery will be conducted in a competitively-neutral manner (e.g., customers that pay for a project through their commodity supplier would be exempt from any duplicative recovery through delivery rates); and (b) adding ", which need not be on a volumetric basis" to the last sentence.

Staff would change Model 2 by:

- Replacing "rate design" with "ratemaking" because, in Staff's view, the latter term is broader and gives the Commission greater leeway to implement cost recovery.

National Grid, which supports many of the points of Model 2, would change Model 2 by:

- Modifying the first bullet to allow consideration of utilities with formula rates. National Grid submits that the parenthetical phrase in the first bullet reading "(or FERC approved formula rate if appropriate)" should be modified to read instead: "(for a TO which has a formula rate filed with FERC defining and allowing recovery of the revenue requirements associated with any costs that include CRPP projects, the TO may recover the project costs in accordance with such FERC approved formula rate)."
- Modifying the third bullet to also ensure that non-LIPA projects with costs allocated to the LIPA transmission district are covered also; that is, protections and assurance of cost recovery must work both ways. National Grid has this same concern with Model 1.
- Modifying the last bullet to provide that the developer has a legal right to judicial review of any rate determination decision of the state regulatory authority.

RESA/SCMC would change Model 2 by adding as bullets:

- The allocation of costs among LSE's will be instituted in a competitively neutral and non-discriminatory manner that does not disadvantage customers taking commodity service from an ESCO; and
- The cost recovery/surcharge mechanism must ensure will be instituted in a competitively neutral and non-discriminatory to customers regardless of their commodity supplier.

MODEL 3: NON-UTILITY/CONTRACT MODEL

As proposed by CPV/NAG:

CPV/NAG predicates this model on: 1) only non-utility developers allowed; and, 2) sponsoring utilities will enter into a contract with the developer.

- The costs incurred by the sponsoring PSC-regulated utility will be allocated among PSC-regulated utilities in accordance with the NYISO-adopted allocation formula in a rate schedule to be filed by the NYISO for recovery by each such utility.
- In response to a competitive solicitation by the PSC, generation or demand-based project developers subject to this process will file project price bids and milestones. The lowest price bid would be deemed to constitute "reasonably incurred" costs.
- The project developer/seller will file the contract with FERC.
- There will be a mechanism established by the Commission to enable recovery from retail ratepayers of investor-owned utility contract payments made in accordance with the cost allocation filed by NYISO with FERC
- NYPA and LIPA costs will be recovered through a mechanism they establish with the NYISO (e.g., FERC tariff, their own NYISO tariff).
- Transmission and non transmission solutions costs would be capped, or subject to adjustment, on a comparable basis.

IPPNY would change Model 3 by:

Eliminating the last sentence from the second bullet because IPPNY does not believe that the structure of the contract or the criteria to determine the selected project should be limited in this phase; these issues should be fully vetted in the second phase of this proceeding.

RESA/SCMC would change Model 3 by adding as a bullet:

- The cost recovery mechanism must ensure that the allocation of costs among LSEs and the recovery of costs in retail distribution rates are instituted in a competitively neutral and non-discriminatory to customers regardless of their commodity supplier.

MODEL 4: COMPETITIVE MARKETS MODEL

As proposed by IPPNY and supported by CPV/NAG:

- In response to a competitive solicitation by the PSC, generation and demand-based project developers will file project price bids and milestones.

- Developers selected will be paid a fixed [$/kw-month] “resource adequacy incentive fee” as an “incentive” to go forward with their reliability projects under a master contract between the developer and either the Responsible TOs and municipalities that have been designated as beneficiaries in the cost allocation process, or, if possible, a state authority. This contract is specifically to transfer PSC specified retail ratepayer funds collected by the TOs and municipalities to the project developer (i.e., payment amount and schedule of payments). Developers will be required to rely on the market revenues to pay their remaining costs for their projects. Since the incentive fee paid to the developer is a fee paid to develop the project, rather than a payment for electric service, market payments will not affect the fee payments received by the developer.

- There will be a mechanism established by the PSC to recover investor-owned utility payments from retail ratepayers in a manner that is non-discriminatory to customers regardless of their commodity supplier. The mechanism will provide a full pass through to retail rates of the investor-owned utility payments through service-class specific delivery surcharges. Ratemaking for the recovery of these costs will be determined on a case-by-case basis.

- NYPA and LIPA costs will be recovered through the master contract.[13]

- NYPA, LIPA and PSC would develop an agreement establishing the conditions under which the Authorities will contract with the project developer for recovery of the project developer’s fee.

- To the extent the Responsible TOs wish to submit a regulated backstop proposal that is transmission based, its proposal would be proffered alongside the proposals submitted under the competitive solicitation. The PSC would determine which project best meets the public interest.

COMMENTS ON THE MODELS

MODEL 1

Attributes

Staff, CPB and MI assert that there are two main reasons for adopting Model 1. These pertain to federal/state jurisdictional issues and to retail ratemaking. Staff and MI’s jurisdictional concern is that were the Commission to agree to allow recovery of state jurisdictional costs in a

[13] In the event that it is decided not to include LIPA and NYPA’s demand and generation projects in the NYISO tariff the converse of the agreement listed in the subsequent bullet would have to be developed.

FERC tariff (i.e., Models 2 or 3), FERC (and the courts) may then determine that the PSC has ceded jurisdiction of not only those costs to FERC but also the entire regulatory backstop process. (FERC staff has stated as much to DPS Staff in telephone conversations.) Staff views the D.C. Circuit Court's Station Power Decision as illustrative of this issue.[14] In that case, the PSC agreed to allow the calculation and recovery of station power costs, which are state-jurisdictional, to be handled in the NYISO's tariff. Even though the PSC had expressly reserved its jurisdiction over retail sales, the court determined that it had ceded its jurisdiction by allowing recovery to occur through a FERC tariff.

In Staff, CPB, and MI's view, Model 1 retains the Commission's ability to ensure that the costs of a jurisdictional project are prudently incurred whereas the risks of using any of the other models overwhelm any benefits they may present. Inasmuch as the Instituting Order concluded (at 17) that "the PSC would oversee the regulated backstop selection process and exercise its authority to review costs associated with the non-transmission, regulated backstop solutions to ascertain that the costs were prudently incurred," the Commission should be extremely reluctant to relinquish any of its jurisdictional authority over generation and demand response reliability backstop projects.

The TOs believe, however, that Staff has overstated the jurisdictional benefits it accords to Model 1 and the jurisdictional concerns related to Model 2. The TOs point out that under Model 2 the PSC would retain the ability to select the generation and DSM project that would proceed and to ensure its consistency with state policy criteria. In addition, under Model 2, the TO/developer would enter into an agreement not to request recovery under the NYISO tariff of any costs found to be imprudent by the PSC, and not to request a change in the FERC approved rate without PSC concurrence. The TOs believe that these protections virtually eliminate any reasonable concerns with respect to PSC oversight of generation and DSM reliability projects. Further, the Station Power case cited by Staff is not relevant, according to the TOs, because it did not involve the kinds of commitments to PSC oversight that are contained in Model 2. While it is unlikely that FERC would increase a rate agreed to by a developer, that very limited risk exists

14 Niagara Mohawk Power Corporation v. FERC, 452 F.3d 822 (D.C. Cir. 2006) (D.C. Circuit Court's Station Power Decision).

under a wholesale contract under Model 1, as well as an agreement for cost of service recovery under Model 2.[15]

From a ratemaking perspective, Staff, CPB and MI assert, Model 1 is also superior because it envisions recovery through TO delivery rates. Retail ratemaking ensures that energy service companies (ESCOs) and full-service utility customers are treated equally because all customers will pay the same delivery surcharge (which need not be volumetric) assigned their respective service-classes. In contrast, Model 2 would recover costs from all allocated wholesale customers, including ESCOs, in a specified zone(s). Traditional retail ratemaking takes these charges and spreads them across all retail customers served by the investor-owned utility and also accords the Commission with the flexibility to tailor the method and timing of customer rate recovery on a project-by-project basis.

For example, let us assume that costs are allocated to the Lower Hudson Valley zones, including NYSEG's Brewster area customers and an ESCO that only serves customers in the Brewster area. Traditional ratemaking would take the dollars paid by NYSEG to the NYISO and spread the costs across all of NYSEG's customers – not just those customers in the Brewster area. The ESCO would be forced to recover the NYISO charges from their customers in only the Brewster area. The end result is customers situated side-by-side paying dramatically different rates for the same project. The alternative is for the Commission to customize rates for customers by NYISO sub-zone; this is a path that Staff, CPB and MI do not recommend.

The TOs believe, however, that Staff has overstated the difficulty in addressing this issue under Model 2. This is a retail rate design issue that the Commission can address. For example, if a utility has the ability to collect different rates by zone it could be an LSE charge, or, if the utility does not have such ability, the charge could be collected as a delivery charge to all of a TOs retail customers. National Grid submits that such collection as a delivery charge could be accomplished if the NYISO allocates to the appropriate TOs (not ESCOs) a reliability charge that the TO would then be allowed by the NYPSC to pass through to customers as a specific labeled component (e.g., Reliability Facilities Charge) of their delivery charge. There is no reason to assume, according to National Grid, that this issue cannot be addressed by a cooperative effort between the Commission and the TOs.

[15] The TOs suggest in the alternative that Model 1 may be appropriate for utility-build or utility-own scenarios for generation or demand-based projects.

Shortcomings

The parties to this proceeding have raised a multitude of concerns with respect to the Model 1 proposal. For instance, IPPNY strongly opposes Model 1 because it believes that this model suffers from serious jurisdictional, market-related and/or administrative problems. IPPNY, moreover, opposes this approach for energy and capacity contracts as beyond the PSC's jurisdiction and believes that, at best, it is needlessly complicated and, at worst, wholly unworkable, for addressing NYPA and LIPA. Under Staff's Model 1, IPPNY asserts, the developer would be assigned an identified return on equity and all revenues received for the project (i.e., energy, capacity, ancillary services, etc.) from the market would be deducted from the monthly payment due to the developer.

In addition, according to IPPNY, the developer of a generation or demand response project would be required to obtain Commission approval of the costs of these projects. Model 1 intrudes upon FERC's jurisdiction because it contemplates that the Commission would review and approve for recovery the costs of generators selling electricity, capacity and ancillary services solely at wholesale, which is within FERC's exclusive jurisdiction.

Some parties believe that a discussion of the potential for the use of cost of service regulation and contractual agreements should not be addressed in Phase 1, but rather, should be put off until Phase 2 of this proceeding. The TOs, however, point out that the opportunity for cost of service regulation for a regulated project is permitted under the NYISO tariff and is an essential aspect of their willingness to agree to assume the responsibility for providing regulated backstop solutions. Other parties believe that the very difference between the cost recovery models, the recovery of transmission costs through the FERC tariff and non-transmission costs via other methods, is an infirmity of Model 1.

National Grid submits that the Staff's cost recovery model should not require a TO to enter into a contract. The issue of who should enter into a regulated contract with a developer is best left open for discussion in Phase II of this proceeding. National Grid, along with the majority of parties that filed comments in the State IRP/Utility Long Term Contracting proceeding (Case 07-E-1507), the predecessor to this proceeding, stated that the Commission should use a mechanism like the Commission's Reliability Portfolio Standard (RPS),[16] which is

[16] Case 03-E-0188, Order Regarding Retail Renewable Portfolio Standard (issued September 24, 2004); and subsequent orders in this docket.

administered by NYSERDA, as opposed to forcing TOs to sign long-term contracts, as a way for the state to achieve its goals. Moreover, the December 27, 2007, Order in Case 07-E-1507 stated that "Staff believes an RPS-type process should be considered one of many approaches the Commission could utilize to ensure adequate, economic, and <u>reliable</u> <u>service</u> and the preservation of environmental values." [Emphasis added.] National Grid adds that the issue of prejudging specific contract mechanisms was also a concern expressed by Commissioner Harris in her dissent in the December 24, 2007 Order.

IPPNY disagrees with Staff's interpretation of the D.C. Circuit Court's Station Power Decision. According to IPPNY, the Court's ruling is grounded on a PSC concession at oral argument that station power netted over one hour is not a retail sale. IPPNY explains that the FERC Order that was the subject of the litigation ruled that station power that is netted over a monthly period is self-supplied and does not constitute a sale. Therefore, IPPNY states, FERC found that self-supplied station power fell outside of PSC jurisdiction.

The Court stated that PSC counsel "agreed that it would be a valid policy judgment on the part of FERC to determine that no retail sale occurred and that no local distribution service was utilized if a generator was net positive over an hour." The Court ruled: "If the Federal Power Act, as petitioners contend, prevents NYISO from exerting authority over state-jurisdictional transactions by netting them out, then any such exertion must be a violation. And, on the other hand, if hourly netting is perfectly consistent with the statute, we see no principled reason why monthly netting violates the Act." Thus, according to IPPNY, the question at hand in the Station Power Proceeding was not whether the PSC had ceded its jurisdiction; rather, the holding turned on the fact that the PSC lacked jurisdiction in the first instance. In IPPNY's view, this case presents the same issue. It is for this core reason, concludes IPPNY, that Model 1 should not be adopted.

Some parties also believe that the goal of Model 1, to keep costs under the control of the PSC, is undermined by the FERC's right to change the terms of a FERC-jurisdictional contract. As a result, they believe that if FERC approves a contract at a higher level than that approved by the PSC in the process outlined in Model 1, the PSC would have to allow the flow-through on a retail rate basis regardless of whether that underlying cost would have resulted in a different project selection by the Commission. Directly related to these concerns are the apprehensions that Model 1 will be unable to achieve clarity and certainty over how costs of projects under consideration compare to one another and the certainty for reasonable cost recovery given the different recovery methodologies.

Another criticism lies in the distinction between a utility self-build project under cost of service regulated rates and under contracts. Some parties believe that a pre-approval of prudence does not necessarily mean that a utility would be willing to sign long-term contracts with generators. Some parties stated that given the PSC's preference for competitive markets, a reliance on utility self-build is a flaw itself. The TOs point out, however, that the NYISO tariff clearly contemplates that reliability projects would be developed by the TOs, and the TOs agreement to undertake the responsibility to provide regulated backstop solutions is based on an understanding that that option will be available. In addition, the TOs point out that the Commission's Order recognizes the utility-build option as a potential solution.[17] Other parties question the jurisdiction of the PSC to authorize the recovery of costs by an "alternate developer" providing reliability because they believe that such a contract would be subject solely to the jurisdiction of the FERC.

Some parties also assert that the participation of independent power producers in offering an independently-developed regulated project would be complicated and, potentially, deterred because they would be ineligible for lightened FERC regulation as an exempt wholesale generator if generators were to obtain direct cost recovery through retail rates. This is particularly an issue with the structure advanced under Example 2, asserts IPPNY. From both a legal and an administrative standpoint, IPPNY continues, it is unclear how a generation project can ensure recovery under this mechanism, and thus, obtain the necessary financing for its project, especially if such cost recovery must come from a number of Responsible TOs. In addition, other parties believe that the PSC does not have jurisdiction to review and approve the costs of a generator selling solely at wholesale.

A further criticism of Model 1 arises in the requirement of a "master contract." Such a contract would be required between the developer and the responsible TOs and municipalities that have been designated as beneficiaries in the cost allocation process. The purpose of such a contract would be to allow the PSC to transfer specified retail ratepayer funds to the project developer.

[17] Instituting Order, at 23.

Some parties suggest that the complexity of multiple contracts could delay and overly complicate the process. Alternatively, other parties believe that a single contract involving all parties could become even more unwieldy and produce similar delays and complexities. Some parties also state that this method interferes too much with competitive markets and the current wholesale power structure. These parties argue that a payment structure similar to that for RPS would more effectively limit the impacts on the competitive markets. Some parties also believe that Model 1 may require the auditing of developer revenues by the Commission or TO when the cost of service regulation option is utilized for non-utility projects in order to ensure that appropriate consumer credits are provided.

The TOs believe that Model 1 has not adequately defined the nature of the agreements to be entered into, the parties who would be signatories to the agreement, or how payments to and from entities not subject to PSC jurisdiction, including LIPA, NYPA and the municipal systems, would be assured. Both LIPA and NYPA have indicated that Model 1 will not provide sufficient assurance of recovery of their costs, and both strongly favor Model 2.

Lastly, some parties believe that the need for an agreement between NYPA, LIPA and the PSC, which establishes the conditions under which the Authorities will contract with the project sponsor for cost recovery, is too complex and will produce a less fair allocation of costs than would reliance upon FERC tariffs.

MODEL 2

Attributes

The TOs do not believe that Model 2 is very different from Model 1 from a jurisdictional perspective, but believe that Model 2 has several distinct benefits because it allows cost recovery for all projects through the FERC-NYISO tariff. In addition, the TOs state that there are state/federal jurisdictional issues that will remain unresolved with either Model 1 or Model 2, i.e., even if Model 1 is adopted, there is a risk that the FERC would have jurisdiction over a project that provides power at wholesale. Model 2 should be preferred because it provides a framework for resolving up front the jurisdictional issues by providing that the project developer will seek approval from the PSC prior to seeking approval for or revising any rate that is on file with the FERC. National Grid submits that approval of rates by either the PSC or by FERC must be subject to judicial review.

Model 2 provides for comparable rate recovery treatment for all types of reliability solutions (transmission, generation and demand-based) and also allows for the continued participation of LIPA and NYPA by providing a cost recovery mechanism that is more compatible with the unique jurisdictional requirements of the Authorities. Model 2 also provides a mechanism that ensures the recovery of costs from all load serving entities (LSEs) in the NYCA to which costs have been allocated under the NYISO's cost allocation methodology, including LIPA, NYPA and municipal systems.

The TOs state that Model 2 provides greater assurance to the developer of full cost recovery because the cost allocation and cost recovery mechanisms will be consistent and co-extensive, thereby subjecting all parties to whom costs have been allocated to the NYISO tariff. The cost allocation methodology under Model 2, the TOs assert, also assures the LSEs that they will not bear more of the project cost than has been assigned to them. It also enables the NYISO to consistently calculate and invoice all reliability project charges to LSEs, based on approved developer costs net of credits to offset project costs from the NYISO market revenues produced by the regulated project, such as TCCs and installed capacity.

Recovery is tariff-based and reaches all wholesale entities by allowing recovery from all LSEs without the requirement of individual contracts between each developer and each entity that is allocated costs, including TOs, state agencies and municipal systems. The TOs also believe, most importantly, that Model 2 allows the PSC to retain its ability to review the prudence of costs incurred for non-transmission projects subject to its jurisdiction because of the TOs' agreement not to seek any costs from FERC greater than what the PSC has authorized or to request an increase in a FERC-approved rate without PSC concurrence. The TOs contend that, given the protections built into Model 2, reasonable concerns with respect to the PSC's ability to oversee the development and prudent costs of generation and demand-based projects have been adequately addressed.

Shortcomings

IPPNY asserts that Model 2 (NYISO-FERC Tariff) suffers from the same jurisdictional flaw as Model 1 because it would allow the Commission to review and restrict the amount of costs that a wholesale generator could recover from FERC in contravention of FERC's exclusive jurisdiction to review and approve wholesale rates. In addition to the jurisdictional flaws, IPPNY believes that both models may run afoul of the parameters defined in the Commission's ERP Order depending upon how the contract is designed (i.e., Example 2 versus Example 1). In its ERP Order, the Commission clearly stated that it preferred cost recovery mechanisms, such as long-term contracts for wholesale generators, which shift only some of the capacity investment risk to ratepayers over fully rate-regulated projects that shift 100 percent of the risks to consumers.[18] Superimposing a cost-of-service backed project onto the competitive market will skew the market results and will not foster efficient operations. In addition, IPPNY continues, it would shift all of the investment risks to consumers, eliminating the one of the greatest benefits the Commission achieved in advancing a competitive electricity market.

In Staff's view, while the TOs have tried to accommodate the "interests" of the PSC by volunteering to limit the amount of recovery the TOs request from the FERC to what the PSC authorizes, Staff believes that Model 2 would still result in the Commission giving up final authority for cost recovery for non-transmission projects, which Staff argues the PSC cannot legally do. In addition, Staff argues that FERC has limited authority to allow non-transmission costs to be recovered through its NYISO tariff.

Others parties dispute this claim, citing FERC's clear statutory authority to regulate wholesale sales of electricity in interstate commerce, and pointing to FERC's exercise of its jurisdiction over both short-term and long-term power contracts. FERC has some precedent in characterizing payments to reliability-must run (RMR) generation as a transmission service, but even FERC considers RMR contracts as short-term arrangements and, therefore, not consistent with the long-term payments envisioned under Model 2. Nevertheless, Staff remains concerned that allowing for blanket filing of all rates for non-transmission solutions at FERC, as mentioned above, could be seen as the PSC relinquishing authority to FERC on this issue. IPPNY does not agree with this interpretation.

As noted, the TOs also suggest that Staff has overstated the jurisdictional concerns related to Model 2. In meetings concerning Model 2, according to the TOs, senior FERC staff has indicated its willingness to consider its use as a way to ensure comparable treatment of all types of reliability solutions, and to consider any state jurisdictional concerns.

Staff argues that cost recovery designed to cover the full costs of constructing new generation or demand-based projects are consistent with state resource adequacy authority. It

[18] Instituting Order, at 23.

also reports that the FERC staff has stated (somewhat in contradiction) that all costs passed through a FERC tariff are jurisdictional and a FERC tariff cannot be used to pass through costs that are not FERC jurisdictional. Staff observes that even though the TOs are willing to promise not to request recovery of costs in excess of a PSC determination, IPPNY's members are not willing to make this commitment and want that provision dropped from Model 2.

IPPNY states that while it may be willing to consider such a proposal for projects that have executed long-term contracts, it believes that it is necessary for the TOs to clarify that its proposal in this regard applies equally to transmission projects that they propose as backstop solutions. Only then will all projects be on an equal footing and equitably treated. Staff notes that without some full agreement from all potential generators or proposed demand side solutions, the certainty offered by the TOs cannot be relied upon. The TOs suggest that such a commitment can be made a condition for the selection of an alternate regulated solution, since a regulated solution will necessarily involve the exercise of Commission authority based on state law and policy. Moreover, there is concern raised about the recovery of cost overruns and the ability of the Commission to address them. As noted above, the TOs believe that these concerns are not justified because the Commission has clear authority to require electric corporations to follow Commission ratemaking requirements where a facility is not recovering all of its revenues from competitive markets, but is relying on a regulatory mechanism to recover some of its costs. Nucor Steel Auburn objects to a surcharge mechanism that does not provide for a full review of the proposal before being included in rates.

In the event Model 4 is not adopted, IPPNY endorses Models 3 and 2 with the modifications that incorporate the changes it proposed, as identified above. For the reasons set forth under Model 1, IPPNY believes that the premise for Staff's concerns regarding Model 2 is faulty. FERC has exclusive jurisdiction over the rates of, and matters affecting the rates of, generators selling exclusively at wholesale. (Those rates may be pursuant to the generator's market based rate authority or a cost-based rate.) The Commission does not have authority to restrict a generator's recovery of costs pursuant to a FERC-jurisdictional tariff. Accordingly, IPPNY asserts, Staff's concern that the Commission would "cede" jurisdiction under this model is misplaced because the Commission cannot cede what it does not have in the first instance.

Staff believes that the major benefit claimed by Model 2's proponents, consistency of recovery across all sources, is applicable only at the wholesale level. In order to obtain consistent treatment at the retail level, there are major obstacles that must be overcome. Model 2 would recover costs from all allocated wholesale customers, including ESCOs, in a specified zone(s). Depending on how these costs are allocated within the TOs' rates, some parties were concerned that ESCO customers could potentially pay for these costs twice or at a higher level than customers otherwise similarly situated, but receiving supply from the TOs. Retail ratemaking is significantly complicated and absent the creation of zonal retail rates could create competitive and other inequities.

As shown in the Brewster example discussed in the context of the attributes of Model 1, the PSC's retail ratemaking takes these charges and spreads them across all retail customers served by the affected investor-owned utilities. MI, CPB and Staff state that Model 2, in contrast, presents the possibility that customers situated side-by-side pay dramatically different rates for the same project in the affected utility service territories. As noted previously, the TOs believe that this is a retail rate design issue that can be resolved through application of the Commission's broad retail ratemaking authority over electric corporations and other market participants. National Grid refers to its earlier comments on this issue.

Another Staff concern is that FERC may overrule the PSC's selection of a reliability backstop. The Commission is obligated under the PSL to consider a variety of public policy concerns, and to weigh the costs and benefits in choosing a project. The selected project might not be simply "least cost" as defined by FERC. Under Model 2, in Staff's view, FERC might object to the contract costs because they were not "least cost," and disallow recovery. Staff believes Model 1 avoids this dilemma by providing cost recovery through PSC rates. The TOs contend that there is no basis for assuming that FERC would not respect state policy objectives related to the development of generation and DSM projects, or would insist on the "cheapest" project, regardless of other relevant policy considerations. The TOs note that this could be treated similarly to certain transmission rates, where FERC accepts the PSC's "rate practices and determinations in the absence of a showing of abuse." E.g., Consolidated Edison Company of New York, Inc., 15 FERC ¶ 61174 (1981).

According to MI, the PSC's ability to "capture" other revenues realized by a reliability backstop solution as an offset to mitigate the cost of the regulated response to customers may not exist or be more difficult than under Model 1. Inasmuch as a regulated backstop solution reflects the failure of the competitive market to address an identified reliability need – thereby prompting the need for customer funding of a regulated project – the Commission should do everything in its power to mitigate the cost of the solution to customers. Such mitigation – in addition to protecting and benefiting customers – also could help make market-based solutions to reliability needs more attractive for developers, thereby minimizing any incentive on the part of developers to forego market responses in favor of regulated projects.

MODEL 3

Attributes

CPG/NAG observe that the Instituting Order favors long-term contracts in which the developer bears the risk of cost overruns. CPG/NAV argues that reliability backstop projects should not be placed in rate base, but rather should be limited to long-term (fixed-price) contracts. This would provide a level playing field for the Commission to choose among projects, without concern for the potential of low-balled estimates followed by cost overruns paid for by ratepayers. National Grid disagrees and refers to its comments regarding Example 4. The selected contracts would be filed at FERC, and costs could then be recovered on a consistent basis. Proponents argue that this approach is consistent with PSC and FERC jurisdictions, and also protects ratepayers from cost overruns.

Shortcomings

Other parties argue that it may not be possible, or even necessarily desirable, to limit reliability backstops to fixed-price contracts. Indeed, National Grid submits that it may not be possible, or even desirable, to even allow such contracts. These parties note that, if a project is needed for reliability but suffers a cost overrun, then the developer may require additional funds to complete the project, above what is allowed in the contract, and has the legal right to request such funds from the appropriate regulatory body, whether PSC or FERC. There may be no practical alternative, at that point, to providing additional funds to get the needed project completed. National Grid states that it should also be recognized that there may be no practical alternative to provide additional funds not only to get the project completed, but also to keep a completed project in service. Thus, ratepayers cannot be fully protected from the risk of cost overruns on reliability backstops, regardless of the mechanisms adopted here. National Grid asserts that, as well as the risk of cost overruns, there is also a risk to ratepayers of insufficient cost recovery, which could require increased costs to either increase the “fixed” price or secure reliability via other sources if, for example, a resource is unable to stay in service. Moreover, there may be circumstances where cost of service is a reasonable basis for cost recovery. National Grid submits that this is not only reasonable, but also could be a less expensive option for ratepayers.

IPPNY disagrees that ratepayers cannot be fully protected from the risk of cost overruns for a project with a fixed-priced contract. The concerns that a developer with cost overruns will seek additional cost recovery or abandon its project can readily be addressed in an evaluation of the developer's financial and technical capability and in contractual milestones and performance guarantees. Moreover, IPPNY states, there is a long history of transmission owners building generation projects and seeking recovery of cost overruns at the Commission. IPPNY submits that a fully rate-regulated project does not eliminate and actually exacerbates the risk of shifting costs to consumers.

In addition, the TOs note, the project may be seeking to recover a portion of its costs through non-market sources (e.g., a long term contract subject to Commission approval or some RPS-like mechanism), which would provide a clear basis for the Commission to evaluate the relative risks and benefits to ratepayers between utility and non-utility projects. The TOs also point out that the NYISO tariff clearly contemplates that reliability projects would be developed by the TOs and that the TOs' agreement to undertake the responsibility to provide regulated backstop solutions is based on an understanding that that option will be available.

National Grid opposes Model 3 also because, from its perspective, the model appears to limit the ability of a TO to propose a planning/CRPP solution. Moreover, National Grid argues, Model 3 contradicts the entire premise of the NYISO CRPP process, which allows for full participation by all market participants, including TOs and any other potential developer of a planning solution. Further, according to National Grid, it appears to attempt to give jurisdiction over transmission solution costs to the PSC, whereas it is clear that such transmission solution costs are subject to FERC jurisdiction.

As in Model 2, Staff, CPB and MI are concerned that FERC may overrule the PSC's selection of a reliability backstop as not "least cost" as defined by FERC. Under both Model 2 and Model 3, they assert, FERC might object to the contract costs because they were not "least cost," and disallow recovery. Indeed, MI, CPB and Staff believe, virtually all of the shortcomings identified with respect to Model 2 apply in at least equal force to Model 3. These parties also note that both Model 3 and Model 4 are not full-fledged models but are more accurately described as mechanisms that either Models 1 or 2 could accommodate.

MODEL 4

Attributes

IPPNY states that in contrast, in the RPS proceeding -- a proceeding where the PSC also espoused its goal to limit impacts to the competitive market to the degree possible -- the PSC adopted an incentive payment approach. Under this approach, developers are paid a fixed kWh payment as an "incentive" to go forward with what would otherwise be uneconomic renewable energy projects. However, the developers are required to rely on the market revenues to pay their remaining costs for their projects. IPPNY proposes adoption of an RPS-like incentive payment structure as Model 4. Such a payment structure would far more effectively limit the impacts on the competitive markets than DPS Staff's proposed structure. It would minimize the shift of investment risk to consumers. In addition, the Model avoids the jurisdictional problems of Models 1 and 2. Neither the Commission nor FERC will need to review and approve wholesale generator project costs for recovery purposes because the project will rely on the incentive payments (a non-electricity product not subject to FERC's jurisdiction) and wholesale market revenues to obtain financing.

As a general matter, IPPNY observes that implementation of a single cost recovery mechanism applicable to all available project selection processes and which respects State and Federal jurisdictional limitations is very difficult and may be impossible. However, inasmuch as Initiative One precedes, rather than follows, Initiative Two, IPPNY is compelled to address the cost recovery process without knowing what the selection process will be. IPPNY prefers Model 4 because it imposes the least harm on the competitive markets and least risk on consumers and it avoids jurisdictional disputes. If Model 4 is not adopted, IPPNY prefers Model 3, with the modification discussed above, and then Model 2 with the modification that the language regarding Commission approval and limitation of cost recovery for wholesale generators must be removed.

In Initiative Two of this Proceeding, the parties are collaborating on evaluation criteria. IPPNY proposes that the ALJ's Report to the Commission and the Commission's Order specifically identify that during Initiative Two of the proceeding, the parties should continue their evaluation of the appropriateness of the model chosen for cost recovery and, if necessary, collaborate to propose, and propose, to the ALJ, enhancements to the Model.

Shortcomings

Staff, CPB and MI assert that Model 4, like Model 3, would limit cost recovery for reliability backstops to fixed-price contracts. Because of its late submission, other parties have not had an opportunity to comment on Model 4. However, Staff believes that the shortcomings identified with respect to Model 3 would also apply to Model 4.

Also, National Grid states that Model 4 appears to prevent TOs from proposing their own generation or demand-based regulated reliability solutions. National Grid asserts that Model 4 inappropriately eliminates a recovery based on and limited to full cost of service with an approved rate of return. National Grid submits that a “master contract” between the developer and TOs may not be necessary or appropriate. Finally, National Grid explains that the RPS program may not be an appropriate analogy if used by the proponents of Model 4 to support their claim that RPS-like incentive payments for regulated reliability solutions would minimize the shift of investment risk to consumers. An RPS project is not necessarily required for reliability. As a result, unlike a regulated reliability project, an RPS project could be allowed to fail and be replaced by other RPS projects without a full rescue/replacement of the total cost of investment by ratepayers.

APPENDIX A
NYISO Developed Cost Allocation Principles & Methodology

1.0 Cost Allocation for Regulated Projects that Resolve a Reliability Need

1.1 Cost Allocation Principles

Cost allocation for regulated transmission solutions to Reliability Needs shall be determined by the NYISO based upon the principle that beneficiaries should bear the cost responsibility. The specific cost allocation methodology in Section 14.2, developed by the NYISO in consultation with ESPWG, incorporates the following elements:

a. The focus of the cost allocation methodology shall be on solutions to violations of specific Reliability Criteria.

b. Potential impacts unrelated to addressing the Reliability Needs shall not be considered for the purpose of cost allocation for regulated solutions.

c. Primary beneficiaries shall initially be those Transmission Districts identified as contributing to the reliability violation.

d. The cost allocation among primary beneficiaries shall be based upon their relative contribution to the need for the regulated solution.

e. The NYISO will examine the development of specific cost allocation rules based on the nature of the reliability violation (*e.g.*, thermal overload, voltage, stability, resource adequacy and short circuit).

f. Cost allocation among Transmission Districts shall recognize the terms of prior agreements among the Transmission Owners, if applicable.

g. Consideration should be given to the use of a materiality threshold for cost allocation purposes.

h. The methodology shall provide for ease of implementation and administration to minimize debate and delays to the extent possible.

i. Consideration should be given to the “free rider” issue as appropriate. The methodology shall be fair and equitable.

j. The methodology shall provide cost recovery certainty to investors to the extent possible.

k. The methodology shall apply, to the extent possible, to Gap Solutions.

l. Cost allocation is independent of the actual triggered project(s), except when allocating Minimum Locational Capacity Requirement (“LCR”) cost responsibilities, and is based on a separate process that results in NYCA meeting its LOLE requirement.

m. There is no implied relationship between the project(s) triggered by the NYISO and the Compensatory MW additions contemplated in the cost allocation process outlined below.

n. The target year is the year in which a need will be met by a backstop solution(s).

o. The trigger year is the year in which the backstop solution must begin to be implemented, driven by the project lead time.

p. Cost allocation for a solution that meets the needs of a target year assumes that backstop solutions of prior years have been implemented.

q. Cost allocation will consider the most recent values for LCRs. LCR must be met for the target year.

APPENDIX B
TOs' Cost Allocation Methodology

1.2 Cost Allocation Methodology

General Reliability Solution Cost Allocation Formula:

The cost allocation mechanism for regulated transmission reliability projects, whether proposed by a Responsible Transmission Owner or a Transmission Owner or Other Developer, would be used as a basis for allocating costs associated with projects that are triggered to meet Reliability Needs identified in the RNA. The formula is not applicable to that portion of a project oversized beyond the smallest technically feasible solution that meets the Reliability Need identified in the RNA. The same cost allocation formula is applied regardless of the project or sets of projects being triggered; however, the nature of the solution set may lead to some terms equaling zero, thereby dropping out of the equation. To ensure that appropriate allocation to the LCR and non-LCR zones occurs, the zonal allocation percentages are developed through a series of steps that first identify responsibility for LCR deficiencies, followed by responsibility for remaining need. This cost allocation process can be applied to any solution or set of solutions that involve a single or multiple cost allocation steps. One formula can be applied to any solution set:

$$\text{Cost Allocation}_i = \Bigg[\frac{\text{LCRdef}_i}{\text{Soln Size}} + \left[\frac{\text{Coincident Peak}_i \times (1 - \text{LCR}_i)}{\sum_{k=1}^{N} \text{Coincident Peak}_k \times (1 - \text{LCR}_k)} \times \frac{\text{Soln STWdef}}{\text{Soln Size}} \right]$$

$$= + \left[\frac{\text{Coincident Peak}_i \times (1 - \text{LCR}_i)}{\sum_{l=1}^{M} \text{Coincident Peak}_l \times (1 - \text{LCR}_l)} \times \frac{\text{SolnVCIdef}}{\text{Soln Size}} \right]$$

$$= + \left[\frac{\text{Coincident Peak}_i}{\sum_{k=1}^{n} \text{Coincident Peak}_k} \times \frac{\text{SolnGNLdef}}{\text{Soln Size}} \right] \times 100\%$$

Where i is for each applicable zone, n represents the total zones in NYCA, m represents the zones isolated by the binding interfaces, and where LCR is defined as the locational capacity requirement in terms of percentage and is equal to zero for those zones without an LCR requirement, (1-LCR) is set equal to zero if the actual value is negative, LCRdef_i is the applicable zonal LCR deficiency, SolnSTWdef is the STWdef for each applicable project, SolnVCIdef is the VCIdef for each applicable project, SolnGNLdef is the GNL def for each applicable project and Soln Size represents the total compensatory MW addressed by each applicable project.

Four step cost allocation methodology for regulated reliability solutions:

a. Step 1 - LCR Deficiency

(i) Any deficiencies in meeting the LCRs for the target year will be referred to as the LCRdef. If the reliability criterion is met once the LCR deficiencies have been addressed, that is LOLE ≤ 0.1 for the target year is achieved, then the only costs allocated will be those related to the LCRdef MW. Cost responsibility for the LCRdef MW will be borne by each deficient locational zone(s), to the extent each is individually deficient.

For a single solution that addresses only an LCR deficiency in the applicable LCR zone, the equation would reduce to:

$$\text{Allocation}_i = \frac{\text{LCRdef}_i}{\text{Soln Size}} \text{ x } 100\%$$

Where i is for each applicable LCR zone, LCRdef_i represents the applicable zonal LCR deficiency, and SolnSize represents the total compensatory MW addressed by the applicable project.

(ii) Prior to the LOLE calculation, voltage constrained interfaces will be recalculated to determine the resulting transfer limits when the LCRdef MW are added.

b. Step 2 - Statewide Resource Deficiency. If the reliability criterion is not met after the LCRdef has been addressed, that is an LOLE > 0.1, then a NYCA Free Flow Test will be conducted to determine if NYCA has sufficient resources to meet an LOLE of 0.1.

(i) If NYCA is found to be resource limited, the NYISO, using the transfer limits and resources determined in Step 1, will determine the optimal distribution of additional resources to achieve a reduction in the NYCA LOLE to 0.1.

(ii) Cost allocation for Compensatory MW added for cost allocation purposes to achieve an LOLE of 0.1, defined as a Statewide MW deficiency (STWdef), will be prorated to all NYCA zones, based on the NYCA coincident peak load. The allocation to locational zones will take into account their locational requirements.

For a single solution that addresses only a statewide deficiency, the equation would reduce to:

$$\text{Allocation}_i = \left[\frac{\text{Coincident Peak}_i \text{ x } \left(1\text{-}LCR_i\right)}{\sum_{k=1}^{n} \text{Coincident Peak}_k \text{ x } \left(1\text{-}LCR_k\right)} \text{ x } \frac{\text{So1nSTWdef}}{\text{So1n Size}} \right] \text{x } 100\%$$

Where *i* is for each applicable zone, n is for the total zones in NYCA, and LCR is defined as the locational capacity requirement in terms of percentage and is equal to zero for those zones without an LCR requirement, (1-LCR) is set equal to zero if the actual value is negative, Soln STWdef is the STWdef for the applicable project, and SolnSize represents the total compensatory MW addressed by the applicable project.

c. Step 3 - Voltage Constrained Interface Deficiency. If the NYCA is not resource limited as determined by the NYCA Free Flow Test, then the NYISO will examine voltage constrained transmission interfaces, using the Binding Interface Test.

(i) The existing output results of MARS ot.09 files indicate the average expected number of hours that each interface is at limit in each flow direction, as well as the average expected number of hours with a loss of load event. These average expected values will be used as an initial indicator to determine the binding interfaces that are impacting LOLE within the NYCA.

(ii) NYISO will review the ot.09 output along with other applicable information that may be available in MARS to make the determination of the binding interfaces and to determine if there is a need to develop a new MARS output table that would provide a clearer and more transparent determination.

(iii) Zone(s) within areas isolated from the rest of NYCA as a result of voltage constrained interface limits are assigned cost responsibility for the Compensatory MW, defined as VCIdef, needed to reach an LOLE of 0.1.

(iv) If one or more areas are isolated as a result of binding interfaces identified through the Binding Interface Test, the NYISO will determine the optimal distribution of Compensatory MW to achieve a NYCA LOLE of 0.1. Compensatory MW will be added until the required NYCA LOLE is achieved or until the voltage constrained interfaces reach their thermal limits. If the interfaces are at their thermal limits and the required NYCA LOLE has not been achieved, Step 4 of the process will be conducted.

(v) The VCIdef MW are allocated to zones isolated as a result of the voltage constrained interface limits, based on their NYCA coincident peaks.

Allocation to locational zones will take into account their locational requirements.

For a single solution that addresses only a binding interface deficiency, the equation would reduce to:

$$\text{Allocation}_i = \left[\frac{\text{Coincident Peak}_i \text{ x } \left(1\text{-}LCR_i\right)}{\sum_{l=1}^{m} \text{Coincident Peak}_l \text{ x } \left(1\text{-}LCR_l\right)} \text{ x } \frac{SolnVCIdef}{\text{Soln Size}} \right] \text{ x } 100\%$$

Where *i* is for each applicable zone, n is for the total zones in NYCA, m is for the zones isolated by the binding interfaces, and where LCR is defined as the locational capacity requirement in terms of percentage and is equal to zero for those zones without an LCR requirement, (1-LCR) is set equal to zero if the actual value is negative, SolnVCIdef is the VCIdef for the applicable project and So1nSize represents the total compensatory MW addressed by the applicable project.

d. Step 4 - General Resource Deficiency. If the reliability criterion is still not met after Step 3, the NYISO will determine the optimal distribution of additional compensatory MW, defined as GNLdef MW, to achieve a NYCA LOLE of 0.1.

(i) The cost for these GNLdef MW will be allocated among all zones in the state, prorated on a NYCA coincident peak load basis.

For a single solution that addresses only a GNL deficiency, the equation would reduce to:

$$\text{Allocation}_i = \left[\frac{\text{Coincident Peak}_i}{\sum_{k=1}^{n} \text{Coincident Peak}_k} \text{ x } \frac{SolnGNLdef}{\text{Soln Size}} \right] \text{ x } 100\%$$

Where *i* is for each applicable zone, n represents the total zones in NYCA, and where SolnGNLdef is the GNLdef for the applicable project and Soln Size represents the total compensatory MW addressed by the applicable project.

e. If, after the completion of Steps 1 through 4, there is a thermal or voltage security issue that does not cause an LOLE violation, it will be deemed a local issue and related costs will not be allocated under this process.

f. Costs related to the deliverability of a resource will be addressed under the NYISO's deliverability procedures.

APPENDIX C
National Grid's Cost Allocation Principles & Methodology

1.0 Cost Allocation for Regulated Project that Resolve a Reliability Need

1.1 Cost Allocation Principles

Cost allocation for regulated transmission solutions to Reliability Needs shall be determined by the NYISO based upon the principle that beneficiaries should bear the cost responsibility. The specific cost allocation methodology in Section 14.2, developed by the NYISO in consultation with ESPWG, incorporates the following elements:

a. The focus of the cost allocation methodology shall be on solutions to violations of specific Reliability Criteria.

b. Potential impacts unrelated to addressing the Reliability Needs shall not be considered for the purpose of cost allocation for regulated solutions.

c. Primary beneficiaries shall initially be those Transmission Districts identified as contributing to the reliability violation.

d. The cost allocation among primary beneficiaries shall be based upon their relative contribution to the need for the regulated solution.

e. The NYISO will examine the development of specific cost allocation rules based on the nature of the reliability violation (*e.g.*, thermal overload, voltage, stability, resource adequacy and short circuit).

f. Cost allocation among Transmission Districts shall recognize the terms of prior agreements among the Transmission Owners, if applicable.

g. Consideration should be given to the use of a materiality threshold for cost allocation purposes.

h. The methodology shall provide for ease of implementation and administration to minimize debate and delays to the extent possible.

i. Consideration should be given to the "free rider" issue as appropriate. The methodology shall be fair and equitable.

j. The methodology shall provide cost recovery certainty to investors to the extent possible.

k. The methodology shall apply, to the extent possible, to Gap Solutions.

l. Cost allocation is independent of the actual triggered project(s), except when allocating Minimum Locational Capacity Requirement ("LCR") deficiency cost responsibilities, and is based on a separate process that results in NYCA meeting its LOLE requirement.

m. There is no implied relationship between the project(s) triggered by the NYISO and the Compensatory MW additions contemplated in the cost allocation process outlined below.

n. The target year is the year in which a need will be met by a backstop solution(s).

o. The trigger year is the year in which the backstop solution must begin to be implemented, driven by the project lead time.

p. Cost allocation for a solution that meets the needs of a target year assumes that backstop solutions of prior years have been implemented.

q. *[This text was deleted with the understanding this was applicable to the "1-LCR" component, not the "LCRdef" component of the formula]*

1.2 Cost Allocation Methodology

General Reliability Solution Cost Allocation Formula:

The cost allocation mechanism for regulated transmission reliability projects, whether proposed by a Responsible Transmission Owner or a Transmission Owner or Other Developer, would be used as a basis for allocating costs associated with projects that are triggered to meet Reliability Needs identified in the RNA. The formula is not applicable to that portion of a project oversized beyond the smallest technically feasible solution that meets the Reliability Need identified in the RNA. The same cost allocation formula is applied regardless of the project or sets of projects being triggered; however, the nature of the solution set may lead to some terms equaling zero, thereby dropping out of the equation. To ensure that appropriate allocation to the LCR and non-LCR zones occurs, the zonal allocation percentages are developed through a series of steps that first identify responsibility for LCR deficiencies, followed by responsibility for remaining need. This cost allocation process can be applied to any solution or set of solutions that involve a single or multiple cost allocation steps. One formula can be applied to any solution set:

$$
\begin{aligned}
\text{Cost Allocation}_i = \Bigg[\frac{\text{LCRdef}_i}{\text{Soln Size}} &+ \left[\frac{\text{Coincident Peak}_i}{\sum_{k=1}^{N} \text{Coincident Peak}_k} \times \frac{\text{Soln STWdef}}{\text{Soln Size}} \right] \\
= \quad &+ \left[\frac{\text{Coincident Peak}_i}{\sum_{l=1}^{M} \text{Coincident Peak}_l} \times \frac{\text{SolnVCIdef}}{\text{Soln Size}} \right] \\
= \quad &+ \left[\frac{\text{Coincident Peak}_i}{\sum^{n} \text{Coincident Peak}_k} \times \frac{\text{SolnGNLdef}}{\text{Soln Size}} \right] \times 100\%
\end{aligned}
$$

$k = 1$

Where i is for each applicable zone, n represents the total zones in NYCA, m represents the zones isolated by the binding interfaces, $LCRdef_i$ is the applicable zonal LCR deficiency, SolnSTWdef is the STWdef for each applicable project, SolnVCIdef is the VCIdef for each applicable project, SolnGNLdef is the GNL def for each applicable project and Soln Size represents the total compensatory MW addressed by each applicable project.

Four step cost allocation methodology for regulated reliability solutions:

a. Step 1 - LCR Deficiency

(i) Any deficiencies in meeting the LCRs for the target year will be referred to as the LCRdef. If the reliability criterion is met once the LCR deficiencies have been addressed, that is LOLE ≤ 0.1 for the target year is achieved, then the only costs allocated will be those related to the LCRdef MW. Cost responsibility for the LCRdef MW will be borne by each deficient locational zone(s), to the extent each is individually deficient.

For a single solution that addresses only an LCR deficiency in the applicable LCR zone, the equation would reduce to:

$$\text{Allocation}_i = \frac{\text{LCRdef}_i}{\text{Soln Size}} \times 100\%$$

Where i is for each applicable LCR zone, $LCRdef_i$ represents the applicable zonal LCR deficiency, and SolnSize represents the total compensatory MW addressed by the applicable project.

(ii) Prior to the LOLE calculation, voltage constrained interfaces will be recalculated to determine the resulting transfer limits when the LCRdef MW are added.

b. Step 2 - Statewide Resource Deficiency. If the reliability criterion is not met after the LCRdef has been addressed, that is an LOLE > 0.1, then a NYCA Free Flow Test will be conducted to determine if NYCA has sufficient resources to meet an LOLE of 0.1.

(i) Cost allocation for Compensatory MW added for cost allocation purposes to achieve an LOLE of 0.1, defined as a Statewide MW deficiency (STWdef), will be prorated to all NYCA zones, based on the NYCA coincident peak load. For a single solution that addresses only a statewide deficiency, the equation would reduce to:

$$\text{Allocation}_i = \left[\frac{\text{Coincident Peak}_i}{\sum_{k=1}^{n} \text{Coincident Peak}_k} \times \frac{\text{So1nSTWdef}}{\text{So1n Size}} \right] \times 100\%$$

Where *i* is for each applicable zone, n is for the total zones in NYCA, Soln STWdef is the STWdef for the applicable project, and SolnSize represents the total compensatory MW addressed by the applicable project.

c. Step 3 - Constrained Interface Deficiency. If the NYCA is not resource limited as determined by the NYCA Free Flow Test, then the NYISO will examine constrained transmission interfaces, using the Binding Interface Test.

(i) The existing output results of MARS ot.09 files indicate the average expected number of hours that each interface is at limit in each flow direction, as well as the average expected number of hours with a loss of load event. These average expected values will be used as an initial indicator to determine the binding interfaces that are impacting LOLE within the NYCA.

(ii) NYISO will review the ot.09 output along with other applicable information that may be available in MARS to make the determination of the binding interfaces and to determine if there is a need to develop a new MARS output table that would provide a clearer and more transparent determination.

(iii) Zone(s) within areas isolated from the rest of NYCA as a result of constrained interface limits are assigned cost responsibility for the Compensatory MW, defined as CIdef, needed to reach an LOLE of 0.1.

(iv) If one or more areas are isolated as a result of binding interfaces identified through the Binding Interface Test, the NYISO will determine the optimal distribution of Compensatory MW to achieve a NYCA LOLE of 0.1. If the NYCA LOLE has not been achieved, Step 4 of the process will be conducted.

(v) The CIdef MW are allocated to zones isolated as a result of the constrained interface limits, based on their NYCA coincident peaks.

For a single solution that addresses only a binding interface deficiency, the equation would reduce to:

$$\text{Allocation}_i = \left[\frac{\text{Coincident Peak}_i}{\sum_{l=1}^{m} \text{Coincident Peak}_l} \times \frac{\textit{SolnCIdef}}{\text{Soln Size}} \right] \times 100\%$$

Where i is for each applicable zone, n is for the total zones in NYCA, m is for the zones isolated by the binding interfaces, SolnCIdef is the CIdef for the applicable project, and So1nSize represents the total compensatory MW addressed by the applicable project.

d. Step 4 - General Resource Deficiency. If the reliability criterion is still not met after Step 3, the NYISO will indicate compensatory MW, defined as GNLdef MW, to achieve a NYCA LOLE of 0.1.

(i) The cost for these GNLdef MW will be allocated among all zones in the state, prorated on a NYCA coincident peak load basis.

For a single solution that addresses only a GNL deficiency, the equation would reduce to:

$$\text{Allocation}_i = \left[\frac{\text{Coincident Peak}_i}{\sum_{k=1}^{n} \text{Coincident Peak}_k} \times \frac{\textit{SolnGNLdef}}{\text{Soln Size}} \right] \times 100\%$$

Where i is for each applicable zone, n represents the total zones in NYCA, and where SolnGNLdef is the GNLdef for the applicable project and Soln Size represents the total compensatory MW addressed by the applicable project.

e. If, after the completion of Steps 1 through 4, there is a thermal or voltage security issue that does not cause an LOLE violation, it will be deemed a local issue and related costs will not be allocated under this process.

f. Costs related to the deliverability of a resource will be addressed under the NYISO's deliverability procedures

CRPP Cost Allocation

National Grid Concerns and Proposed Alternatives

Presented to ESPWG

March 4, 2008

Introduction

- **Specific cost allocation formulas for projects needed to maintain Statewide reliability are currently being considered by DPS Staff in the ERP proceeding and by the NYISO in Attachment Y.**

- **National Grid would like to revise these formulas so that they:**
  - do not excessively allocate the costs of a regulated reliability solution to Zones that don't contribute to a Statewide reliability need.
  - do not disproportionately allocate the costs of a regulated reliability solution to ROS Zones **if/after** a Locational Capacity Requirement ("LCR") deficiency has been addressed.

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Outline of the Proposed Cost Allocation Process (From August 15, 2007 ESPWG Presentation)

The RNA has identified a Statewide reliability need (i.e. projects are needed in order to satisfy NYCA LOLE criteria at or below 0.1).

Step 1 – Any zone with insufficient resources to satisfy an applicable LCR is considered a Zone with an LCR deficiency (“LCRdef”). Cost responsibility for solutions, or portions of solutions, addressing LCR deficiencies will be borne by each LCR deficient Zone to the extent each is individually deficient.

Step 2 – If/after any LCR deficiencies is resolved, the cost of a Statewide regulated reliability project gets allocated to Zones based on each Zone’s share of the coincident peak load multiplied by a factor of “1-LCR.” The “1-LCR” adjustment would result in the removal of a significant amount of load from Zones J and K (e.g. 80% and 99% respectively) in the cost allocation formula for a regulated solution that addresses a Statewide resource deficiency.

Step 3 – If Zones are import constrained and transfer is based on a *voltage limit,* the “Bounded Area” will be allocated the cost to restore transfer up to the thermal limit. The cost of a Statewide regulated reliability solution goes through the process described in Step 2.

Step 4 – If the reliability criteria is still not met after step 3, the cost for the remaining “general resource deficiency” will be allocated to each zone based on its pro-rata share of contribution to the coincident peak load of the system.

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Cost Allocation Results

- **Starting with Step 2 – Assume $500 million project implemented for a Statewide deficiency subsequent to any LCRdef being addressed.**

Zone	2012 Study Case Reliability Index (LOLE)	2012 Coincident Peak Load Forecast	Peak Load (%)	$500 million Cost Allocation: Load Ratio Share ($ in millions)	(1- LCR) Adjusted Peak Load	(1-LCR) Adjusted Peak Load (%)	$500 million Cost Allocation: (1-LCR) Adjusted Peak Load ($ in millions)
A		2,734	7.7%	$38	2,734	13.8%	$69
B	0.08	2,251	6.3%	$32	2,251	11.3%	$57
C		3,036	8.5%	$43	3,036	15.3%	$76
D		876	2.5%	$12	876	4.4%	$22
E	0.03	1,442	4.1%	$20	1,442	7.3%	$36
F		2,280	6.4%	$32	2,280	11.5%	$57
G		2,411	6.8%	$34	2,411	12.1%	$61
H		655	1.8%	$9	655	3.3%	$16
I	0.18	1,612	4.5%	$23	1,612	8.1%	$41
J	0.18	12,645	35.6%	$178	2,529	12.7%	$64
K	0.03	5,624	15.8%	$79	56	0.3%	$1
NYCA	0.19	35,566	100.0%	$500	19,882	100.0%	$500

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National Grid's Concerns With the Proposed Cost Allocation Formula.

- **If Zones J and K have sufficient internal resources to satisfy their respective LCRs, this <u>does not</u> mean that they are more reliable than Zones without LCRs or that Zones J and K no longer contribute to a Statewide reliability need.**

- **Simply having an LCR is not a basis for avoiding the cost responsibility for a Statewide deficiency solution.**
    - Many of the ROS Zones <u>do not contribute to a Statewide reliability need</u> (i.e. 0.00 LOLE) and will have sufficient resources throughout the 10 year planning horizon.
    - Consumers in ROS Zones pay for their applicable LSE/TOs capacity requirements including PPAs.
    - A non-LCR zone may have access to a greater amount of deliverable capacity and contribute less to a statewide reliability need than an LCR zone - even after the LCR zone has addressed any LCR deficiencies

- **In fact, on the basis of Contribution to the Statewide reliability violation/Zonal LOLEs, it's not clear why many of the effected Zones should have any cost responsibilities for a Statewide regulated reliability solution.**

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National Grid's Suggested Cost Allocation Alternatives for Statewide Reliability Solutions.

1. **LOLE Ratio Share - Develop a method of cost allocation based on each Zone's contribution to the NYCA LOLE. Unlike the Binding Interface Test, this method will bring Zones that are resource deficient but not import constrained into the cost sharing processes for a Statewide solution.**

2. **Binding Interface Test - Import constrained Zones or "Bounded Areas" that contribute (TBD) to the NYCA LOLE violation should indicate the responsible TO(s), the likely location of a generation/DSM solution, where additional transmission capability is needed, and be appropriately allocated costs for a Statewide solution.**

3. **Revise the current proposal.**
   - Eliminate the "1-LCR" adjustment (in Step 2 of the proposal presented to the ESPWG on August 15, 2007) for the allocation of costs for regulated reliability solutions to any statewide resource deficiencies remaining after any LCR deficiencies have been addressed.
   - Replace the "1-LCR" adjustment with "1-LCRdef" for the allocation of costs for regulated reliability solutions to any Statewide resource deficiencies remaining after any LCR deficiencies have been addressed.
   - Specify that the cost of any project - regardless of its location - that is used to address an LCR deficiency is Step 1. For example, if a Zone is LCR deficient by a 750 MW but a 1,000 MW regulated reliability project in a ROS Zone provides a similar LOLE benefit, then the cost of the 1,000 MW plant in ROS Zone would be allocated to Zone J.

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Appendix A

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Table 3.3: NYCA Load and Resource Margins 2008 to 2017

Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Peak Load										
NYCA	33,871	34,300	34,734	35,141	35,566	35,962	36,366	36,749	37,141	37,631
Zone J	11,975	12,150	12,325	12,480	12,645	12,780	12,915	13,030	13,140	13,360
Zone k	5,485	5,541	5,607	5,664	5,730	5,791	5,855	5,919	6,002	6,076
Resources										
NYCA										
"- Capacity"	38,917	39,257	38,396	38,396	38,396	38,284	38,284	38,284	38,284	38,284
"- SCR"	1323	1323	1323	1323	1323	1323	1323	1323	1323	1323
Total	40,240	40,580	39,719	39,719	39,719	39,607	39,607	39,607	39,607	39,607
Zone J										
"- Capacity"	10,019	10,019	9,128	9,128	9,128	9,015	9,015	9,015	9,015	9,015
"- SCR"	468.7	468.7	468.7	468.7	468.7	468.7	468.7	468.7	468.7	468.7
Total	10,487	10,487	9,596	9,596	9,596	9,484	9,484	9,484	9,484	9,484
Zone K										
"- Capacity"	5,612	5,922	5,922	5,922	5,922	5,922	5,922	5,922	5,922	5,922
"- SCR"	159.5	159.5	159.5	159.5	159.5	159.5	159.5	159.5	159.5	159.5
Total	5,772	6,082	6,082	6,082	6,082	6,082	6,082	6,082	6,082	6,082
NYCA Resource Margin % (1)	118.8%	118.3%	114.4%	113.0%	111.7%	110.1%	108.9%	107.8%	106.6%	105.3%
Zons J Res./Load/ Ratio	87.6%	86.3%	77.9%	76.9%	75.9%	74.2%	73.4%	72.8%	72.2%	71.0%
Zons K Res./Load Ratio	105.2%	109.8%	108.5%	107.4%	106.1%	105.0%	103.9%	102.7%	101.3%	100.1%

Appendix B

12/10/07; NYISO CRPP 2008 Reliability Needs Assessment Page I-15

Table 4.4: LOLE for the RNA Study Case Transfer Limits

Area/Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
AREA-A										
AREA-B			0.03	0.04	0.08	0.13	0.20	0.30	0.41	0.48
AREA-C										
AREA-D										
AREA-E			0.01	0.01	0.03	0.05	0.09	0.16	0.23	0.25
AREA-F										
AREA-G						0.01	0.02	0.03	0.04	0.04
AREA-H										
AREA-I	0.01	0.01	0.06	0.08	0.18	0.30	0.42	0.59	0.76	0.82
AREA-J		0.01	0.06	0.08	0.18	0.32	0.46	0.65	0.81	0.85
AREA-K			0.01	0.01	0.03	0.06	0.07	0.13	0.23	0.26
NYCA	0.01	0.01	0.07	0.09	0.19	0.34	0.47	0.67	0.85	0.90

APPENDIX E
Staff's Cost Allocation Methodology

1.2 Cost Allocation Methodology

General Reliability Solution Cost Allocation Formula:

The cost allocation mechanism for regulated transmission reliability projects, whether proposed by a Responsible Transmission Owner or a Transmission Owner or Other Developer, would be used as a basis for allocating costs associated with projects that are triggered to meet Reliability Needs identified in the RNA. The formula is not applicable to that portion of a project oversized beyond the smallest technically feasible solution that meets the Reliability Need identified in the RNA. The same cost allocation formula is applied regardless of the project or sets of projects being triggered; however, the nature of the solution set may lead to some terms equaling zero, thereby dropping out of the equation. To ensure that appropriate allocation to the LCR and non-LCR zones occurs, the zonal allocation percentages are developed through a series of steps that first identify responsibility for LCR deficiencies, followed by responsibility for remaining need. This cost allocation process can be applied to any solution or set of solutions that involve a single or multiple cost allocation steps. One formula can be applied to any solution set:

$$
\begin{aligned}
\text{Cost Allocation}_i = \Bigg[\frac{\text{LCRdef}_i}{\text{Soln Size}} &+ \left[\frac{\text{Coincident Peak}_i \text{ x } (1 + \text{IRM} - \text{LCR}_i)}{\sum_{k=1}^{N} \text{Coincident Peak}_k \text{ x } (1 + \text{IRM} - \text{LCR}_k)} \text{ x } \frac{\text{Soln STWdef}}{\text{Soln Size}} \right] \\
= &+ \left[\frac{\text{Coincident Peak}_i \text{ x } (1 + \text{IRM} - \text{LCR}_i)}{\sum_{l=1}^{M} \text{Coincident Peak}_l \text{ x } (1 + \text{IRM} - \text{LCR}_l)} \text{ x } \frac{\text{SolnVCIdef}}{\text{Soln Size}} \right] \\
= &+ \left[\frac{\text{Coincident Peak}_i}{\sum_{k=1}^{n} \text{Coincident Peak}_k} \text{ x } \frac{\text{SolnGNLdef}}{\text{Soln Size}} \right] \text{ x } 100\%
\end{aligned}
$$

Where i is for each applicable zone, n represents the total zones in NYCA, m represents the zones isolated by the binding interfaces, IRM is the statewide reserve margin, and where LCR is defined as the locational capacity requirement in terms of percentage and is equal to zero for those zones without an LCR requirement, LCRdef_i is the applicable zonal LCR deficiency, SolnSTWdef is the STWdef for each applicable project, SolnVCIdef is the VCIdef for each applicable project, SolnGNLdef is the GNL def for each applicable project and Soln Size represents the total compensatory MW addressed by each applicable project.

Four step cost allocation methodology for regulated reliability solutions:

a. Step 1 - LCR Deficiency

(i) Any deficiencies in meeting the LCRs for the target year will be referred to as the LCRdef. If the reliability criterion is met once the LCR deficiencies have been addressed, that is LOLE $\leq$ 0.1 for the target year is achieved, then the only costs allocated will be those related to the LCRdef MW. Cost responsibility for the LCRdef MW will be borne by each deficient locational zone(s), to the extent each is individually deficient.

For a single solution that addresses only an LCR deficiency in the applicable LCR zone, the equation would reduce to:

$$\text{Allocation}_i = \frac{\text{LCRdef}_i}{\text{Soln Size}} \times 100\%$$

Where i is for each applicable LCR zone, LCRdef_i represents the applicable zonal LCR deficiency, and SolnSize represents the total compensatory MW addressed by the applicable project.

(ii) Prior to the LOLE calculation, voltage constrained interfaces will be recalculated to determine the resulting transfer limits when the LCRdef MW are added.

b. Step 2 - Statewide Resource Deficiency. If the reliability criterion is not met after the LCRdef has been addressed, that is an LOLE > 0.1, then a NYCA Free Flow Test will be conducted to determine if NYCA has sufficient resources to meet an LOLE of 0.1.

(i) If NYCA is found to be resource limited, the NYISO, using the transfer limits and resources determined in Step 1, will determine the optimal distribution of additional resources to achieve a reduction in the NYCA LOLE to 0.1.

(ii) Cost allocation for Compensatory MW added for cost allocation purposes to achieve an LOLE of 0.1, defined as a Statewide MW deficiency (STWdef), will be prorated to all NYCA zones, based on the NYCA coincident peak load. The allocation to locational zones will take into account their locational requirements.

For a single solution that addresses only a statewide deficiency, the equation would reduce to:

$$\text{Allocation}_i = \left[\frac{\text{Coincident Peak}_i \text{ x } \left(1+\text{IRM-}LCR_i\right)}{\sum_{k=1}^{n} \text{Coincident Peak}_k \text{ x } \left(1+\text{IRM-}LCR_k\right)} \text{ x } \frac{\text{SolnSTWdef}}{\text{Soln Size}} \right] \text{ x } 100\%$$

Where *i* is for each applicable zone, n is for the total zones in NYCA, IRM is the statewide reserve margin, and LCR is defined as the locational capacity requirement in terms of percentage and is equal to zero for those zones without an LCR requirement, Soln STWdef is the STWdef for the applicable project, and SolnSize represents the total compensatory MW addressed by the applicable project.

c. Step 3 - Voltage Constrained Interface Deficiency. If the NYCA is not resource limited as determined by the NYCA Free Flow Test, then the NYISO will examine voltage constrained transmission interfaces, using the Binding Interface Test.

(i) The existing output results of MARS ot.09 files indicate the average expected number of hours that each interface is at limit in each flow direction, as well as the average expected number of hours with a loss of load event. These average expected values will be used as an initial indicator to determine the binding interfaces that are impacting LOLE within the NYCA.

(ii) NYISO will review the ot.09 output along with other applicable information that may be available in MARS to make the determination of the binding interfaces and to determine if there is a need to develop a new MARS output table that would provide a clearer and more transparent determination.

(iii) Zone(s) within areas isolated from the rest of NYCA as a result of voltage constrained interface limits are assigned cost responsibility for the Compensatory MW, defined as VCIdef, needed to reach an LOLE of 0.1.

(iv) If one or more areas are isolated as a result of binding interfaces identified through the Binding Interface Test, the NYISO will determine the optimal distribution of Compensatory MW to achieve a NYCA LOLE of 0.1. Compensatory MW will be added until the required NYCA LOLE is achieved or until the voltage constrained interfaces reach their thermal limits. If the interfaces are at their thermal limits and the required NYCA LOLE has not been achieved, Step 4 of the process will be conducted.

(v) The VCIdef MW are allocated to zones isolated as a result of the voltage constrained interface limits, based on their NYCA coincident peaks.

Allocation to locational zones will take into account their locational requirements.

For a single solution that addresses only a binding interface deficiency, the equation would reduce to:

$$\text{Allocation}_i = \left[\frac{\text{Coincident Peak}_i \text{ x } \left(1+\text{IRM-}LCR_i\right)}{\sum_{l=1}^{m} \text{Coincident Peak}_l \text{ x } \left(1+\text{IRM-}LCR_l\right)} \text{ x } \frac{SolnVCIdef}{\text{Soln Size}} \right] \text{ x } 100\%$$

Where *i* is for each applicable zone, n is for the total zones in NYCA, m is for the zones isolated by the binding interfaces, IRM is the statewide reserve margin, and where LCR is defined as the locational capacity requirement in terms of percentage and is equal to zero for those zones without an LCR requirement, SolnVCIdef is the VCIdef for the applicable project and So1nSize represents the total compensatory MW addressed by the applicable project.

d. Step 4 - General Resource Deficiency. If the reliability criterion is still not met after Step 3, the NYISO will determine the optimal distribution of additional compensatory MW, defined as GNLdef MW, to achieve a NYCA LOLE of 0.1.

(i) The cost for these GNLdef MW will be allocated among all zones in the state, prorated on a NYCA coincident peak load basis.

For a single solution that addresses only a GNL deficiency, the equation would reduce to:

$$\text{Allocation}_i = \left[\frac{\text{Coincident Peak}_i}{\sum_{k=1}^{n} \text{Coincident Peak}_k} \text{ x } \frac{Soln\ GNLdef}{\text{Soln Size}} \right] \text{ x } 100\%$$

Where *i* is for each applicable zone, n represents the total zones in NYCA, and where SolnGNLdef is the GNLdef for the applicable project and Soln Size represents the total compensatory MW addressed by the applicable project.

e. If, after the completion of Steps 1 through 4, there is a thermal or voltage security issue that does not cause an LOLE violation, it will be deemed a local issue and related costs will not be allocated under this process.

f. Costs related to the deliverability of a resource will be addressed under the NYISO’s deliverability procedures

APPENDIX F

Staff's Discussion on Cost Allocation and Consistency with ICAP Market Allocation

The NYISO reliability backstop solutions are intended, in part, to ensure sufficient installed capacity (ICAP) to meet the minimum statewide and locational ICAP requirements. Suppose that all of this capacity were to be procured under the NYISO reliability backstop process. It would appear reasonable for the cost allocation to be consistent with the allocation of ICAP requirements under the NYISO's ICAP market rules. This consistency holds for the Staff proposal; however, it does not hold for the Straw Proposal or National Grid's proposal.

Under Step 1 of the cost allocation process, NYC loads would be responsible for 100% of the cost of NYC capacity needed to meet the NYC locational capacity requirement (NYC LCR, expressed as a percentage of NYC peak load), and similarly LI loads would be responsible for 100% of the cost of LI capacity needed to meet the LI locational capacity requirement (LI LCR). This is consistent with the NYISO's ICAP market rules, which require NYC and LI loads to procure (and pay for) sufficient capacity to meet their respective locational requirements. There is no disagreement over Step 1.

Step 2 of the cost allocation process would address the remaining statewide need for capacity. Staff's proposal would mimic the existing NYISO allocation of minimum statewide ICAP requirements. The NYISO's ICAP market rules require loads to procure sufficient total capacity to meet the system peak load plus an installed reserve margin (IRM), expressed as a percentage of peak load. Loads in NYC, accordingly, must procure sufficient total capacity to meet (1+IRM) x NYC peak load, loads on LI must procure sufficient total capacity to meet (1+IRM) x LI peak load, and loads in the rest of state (ROS) must procure sufficient total capacity to meet (1+IRM) x ROS peak load. NYC and LI loads, however, have already procured part of their required total capacity in order to meet their respective locational requirements. Thus, the remaining amount of capacity that NYC loads must procure via the statewide ICAP market is (1+IRM-NYC LCR) x NYC peak load, and similarly the remaining capacity which LI loads must procure via the statewide ICAP market is (1+IRM-LI LCR) x LI peak load. Staff's proposal would thus allocate the costs of statewide solutions in Step 2 via the factor (1+IRM-LCR), where LCR is the locational requirement for NYC or LI (LCR is zero for the ROS loads).

In contrast to Staff's proposal, the Straw proposal would allocate the costs in Step 2 via the factor (1-LCR). In the above example, this would lead to a lower allocation of capacity costs to NYC and LI than would obtain under the ICAP market rules. The proponents of this proposal have not explained why such a lower allocation to NYC and LI is appropriate.

On the other hand, National Grid's proposal would allocate the costs in Step 2 without any credit for the costs NYC and LI incurred in meeting their locational requirements. In the above example, NYC and LI would have to pay for their full load ratio share of the remaining statewide requirements, as well as all of the NYC and LI capacity. Thus, NYC and LI loads would effectively be paying for significantly more capacity than (1+IRM) times their respective peak loads. By contrast, ROS loads would effectively be paying for significantly less capacity than

(1+IRM) times their respective peak loads. Staff does not believe that such a deviation from the allocations that would obtain under the ICAP market rules has been adequately justified.

Appendix G illustrates the allocation of capacity under the minimum ICAP requirements, vs. the allocation of capacity costs under the alternative cost allocation proposals. Under the ICAP market rules, statewide loads would be responsible for 41,180 MW of total capacity, of which 15699 MW would be procured from NYC and LI localities, while the remaining 25,481 MW would be procured from the statewide market, and allocated as shown under "Statewide Req." Thus NYC load would be responsible for procuring 4541 MW of statewide capacity, in addition to its 9952 MW of NYC capacity, for a total of 14,493 MW, equal to (1+IRM) times NYC peak load.

Under Staff's proposal, NYC load would pay for 9952 MW of NYC capacity plus 4541 MW of statewide capacity (17.8% of 25481 MW), for a total of 14493 MW, just meeting its total requirement under the ICAP market rules. Under the Straw proposal, NYC load would pay for 9952 MW of NYC capacity plus 3227 MW of statewide capacity (12.7% of 25481 MW), for a total of 13179 MW, short of its total requirement under the ICAP market rules. Under National Grid's proposal, NYC load would pay for 9952 MW of NYC capacity plus 8968 MW of statewide capacity (35.2% of 25481 MW), for a total of 18920 MW, well above its total requirement under the ICAP market rules. Staff recommends, therefore, its proposed cost allocation method (1+IRM-LCR) as most consistent with the NYISO's existing ICAP market rules.

Alternative Cost Allocations for Statewide Solutions

APPENDIX G

							Statewide Cost Allocation Factors		
							Straw	Staff	NG
Zone	Peak Load	LCR	Total Req	LCR Req	Statewide Req	Straw Capacity	(1-LCR)	(1+IRM-LCR)	1
A	2926		3409	0	3409	2926	14.9%	13.4%	8.3%
B	2076		2419	0	2419	2076	10.6%	9.5%	5.9%
C	2906		3385	0	3385	2906	14.8%	13.3%	8.2%
D	821		956	0	956	821	4.2%	3.8%	2.3%
E	1340		1561	0	1561	1340	6.8%	6.1%	3.8%
F	2317		2699	0	2699	2317	11.8%	10.6%	6.6%
G	2405		2802	0	2802	2405	12.2%	11.0%	6.8%
H	677		789	0	789	677	3.4%	3.1%	1.9%
I	1635		1905	0	1905	1635	8.3%	7.5%	4.6%
NYC (J)	12440	0.8	14493	9952	4541	2488	12.7%	17.8%	35.2%
LI (K)	5805	0.99	6763	5747	1016	58	0.3%	4.0%	16.4%
Total	35348		41180	15699	25481	19649	100.0%	100.0%	100.0%

IRM= 16.5%

Adapted from "Examples of Cost Allocation for Reliability Projects 08-13-07," Case 1.

Notes:
Total Req = Load x (1+IRM)
LCR Req = Load x LCR
Statewide Req = Total Req - LCR Req., i.e. Load x (1+IRM-LCR), procured from Statewide ICAP Market
Straw Capacity = Load x (1-LCR), as defined in Straw Proposal
Straw Allocation = TOs Capacity % of Total
Staff Allocation = Statewide Req % of Total
NG Allocation = Peak Load % of Total