STATE OF NEW YORK DEPARTMENT OF PUBLIC SERVICE
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June 26, 2008

Hon. Jaclyn A. Brilling
Secretary
Department of Public Service
Three Empire State Plaza
Albany, New York 12223-1350

Re: Case 07-M-0906 – Iberdrola, S.A., Energy East Corporation, RGS Energy Group, Inc., Greene Acquisition Capital, Inc., New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation – Joint Petition For Approval of the Acquisition of Energy East Corporation by Iberdrola, S.A.

Dear Secretary Brilling:

Enclosed please find Staff's Brief on Exceptions in the captioned proceeding. A copy has been served on all active parties via e-mail, and regular mail to parties so requesting.

Very truly yours,

Leonard Van Ryn

Leonard Van Ryn
Sean Mullany
Staff Counsel

Enclosure
cc: All Active Parties

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 07-M-0906 - Iberdrola, S.A., Energy East Corporation, RGS Energy Group, Inc., Greene Acquisition Capital, Inc., New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation – Joint Petition For Approval of the Acquisition of Energy East Corporation by Iberdrola, S.A.

STAFF BRIEF ON EXCEPTIONS

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STAFF BRIEF ON EXCEPTIONS

STATEMENT OF THE CASE

In a Recommended Decision (RD) issued June 16, 2008 in this proceeding, Administrative Law Judge (ALJ) Rafael A. Epstein made recommendations on the proposed acquisition of Energy East Corporation (Energy East Corp.) by Iberdrola, S.A. (Iberdrola). Energy East is the holding company for New York State Electric & Gas Corporation (NYSEG) and Rochester Gas and Electric Corporation (RG&E), which provide electric and gas distribution and transmission (T&D) service across much of upstate New York. Iberdrola is an international holding company owning T&D and generation subsidiaries in Europe and South America, numerous non-utility operations in Europe and the Americas, and gas storage and wind generation facilities in the U.S., with a particular interest in developing additional wind generation projects. A procedural history for this proceeding is set forth at RD 12-14.

A. The Issues Raised in This Proceeding

Iberdrola's proposed acquisition of Energy East is a transaction that raises a plethora of rate and regulatory issues. Those issues fall primarily into three categories. Structural and financial protections are needed to insulate the regulated operations of NYSEG and RG&E from any adverse effects that might flow from Iberdrola's management of its far-flung business empire. The benefits New York ratepayers will realize as a result of this transaction must be sufficient to meet the positive benefits test for approval under Public Service Law (PSL) §70, after offsetting any risks attending this transaction. The exercise of vertical market power, inherent in Iberdrola's proposal to own both T&D utilities and wind generation facilities, must be prevented. Each of these issues raises a number of complexities.

Financial and structural protections should be sufficient to insulate New York ratepayers from any business failures that occur at the Iberdrola holding company level, or at any of Iberdrola's subsidiaries. The financial conditions sufficient to meet that requirement were set forth in detail in the KeySpan/Grid Order.[1] Those same conditions should be adopted

[1] Case 06-M-0878, National Grid PLC and KeySpan Corporation, Order Authorizing Acquisition Subject to Conditions and Making Some Revenue Requirement Determinations For KeySpan Energy Delivery New York and KeySpan Energy Delivery Long Island (issued September 17, 2007).

here, including appropriate accounting treatment for the acquisition premium Iberdrola will pay for Energy East’s stock; conditions on credit quality; and, restrictions on dividend payments and participation in money pools.

Structural protections begin with the “golden share.” That device prevents Iberdrola from pushing NYSEG and RG&E into voluntary bankruptcy because of adverse financial events at the Iberdrola holding company level or at any of its subsidiaries. Additional reporting requirements and an enhanced Code of Conduct are also needed, to render the relationship between Iberdrola and NYSEG and RG&E amenable to the regulatory oversight that protects ratepayers from bearing unreasonable allocations or the draining away of funds necessary to support regulated T&D service.

In order to gain approval under PSL §70, Iberdrola is required to offer benefits to New York ratepayers that satisfy the positive benefits test established under the KeySpan/Grid and other Orders. The benefits Iberdrola proposed initially were either ephemeral or illusory and so were insufficient to meet the positive benefits test. Subsequent tangible monetary benefit offers remain inadequate. Moreover, because of the risks attending Iberdrola’s complex holding company operations, the level of benefits must first offset those risks before a positive benefit can be found.

It is crucial that the benefits ratepayers will realize be incorporated in rates promptly, so that their value is not lost. To ensure that the benefits are recognized, new rate plans are needed for NYSEG and RG&E. The terms and conditions of those rate plans should be decided in conjunction with a decision on the level of benefits that is adequate to justify approval. The rate plans should also comport with all existing Commission policies.

Finally, the transaction should be approved only if compliance with the Commission's VMP Policy Statement can be achieved,[2] or the harms attending the potential for the exercise of vertical market power (VMP) described there can be mitigated. That Policy Statement describes the adverse impacts ratepayers suffer upon the conjoining in one entity of ownership of T&D operations and electric generation plant. Iberdrola should not be allowed to exercise vertical market power to the disadvantage of ratepayers.

B. Iberdrola's Positions

While Iberdrola characterizes many of Staff's positions in this proceeding as unreasonable, Iberdrola's positions are riddled with inconsistencies that render many of its arguments unpersuasive. Iberdrola complains that Staff's

[2] Case 96-E-0900, et al., Orange and Rockland Utilities, Inc., et al., Statement of Policy Regarding Vertical Market Power (issued July 17, 1998).

proposal to require $644 million in tangible benefits for NYSEG and RG&E ratepayers as a condition of approval of the transaction is excessive. Iberdrola, however, is willing to award Energy East's shareholders a premium in the amount of $930 million, to support a total compensation package to company executives of up to $78 million, and to fund at least $44 million in payments to investment bankers, advisors and attorneys. In contrast, Iberdrola offers ratepayers only $201 million (Exh. 50). The Commission should reject the proposition that, in light of Iberdrola's liberal disbursement of more than $1.0 billion in cash for the benefit of other participants to this transaction, the more than 1,200,000 NYSEG and RG&E ratepayers are entitled to only the paltry $201 million in monetary benefits Iberdrola offers them.

Iberdrola also insists that its proposed investment of up to $2.0 billion in wind generation projects in New York is contingent upon approval of its acquisition of the NYSEG and RG&E regulated utility operations. But Iberdrola dodges making a binding commitment to invest $2.0 billion, or any other amount, whether or not the transaction is approved. Moreover, there is no link between the wind generation investment and ownership of the NYSEG and RG&E regulated utilities, as Iberdrola's own actions demonstrate. It proposes to develop wind projects in states like Oregon and Pennsylvania, where it has no plans to own regulated utilities, but it fails to build wind projects in Maine, where it will own Central Maine Power Company, a utility very similar to NYSEG and RG&E. As a result, Iberdrola's proposed $2.0 billion investment is not connected to the transaction the Commission is asked to review -- which is Iberdrola's acquisition of NYSEG and RG&E.

Finally, Iberdrola argues that it may own wind generation facilities and the NYSEG and RG&E utilities without creating vertical market power. That contention cannot survive a simple reading of the definition of vertical market power -- which is the leveraging of market power in one stage of the production process to gain advantage in a different stage of the production process. Since Iberdrola will control monopoly transmission and distribution companies at the electricity delivery stage of production, it can leverage that monopoly power to the benefit of its wind facilities at the electricity generation stage of production.

Nonetheless, in the event that the Commission decides approval of the transaction is warranted upon less than tangible monetary benefits in the amount of Staff's $644 million, or that Iberdrola may own wind generation facilities if vertical market power impacts are mitigated, Staff presents alternatives to the positions it took earlier in this proceeding. The $2.0 billion investment Iberdrola proposes, and the amount of tangible monetary benefits it must provide ratepayers, can be linked. If Iberdrola commits to the development of wind projects in New York the investments it promises, the amount of the monetary benefits due ratepayers could be reduced. If Iberdrola fails to keep it wind investment promises, however, substantial monetary benefits, in the form of rate reductions, should accrue to NYSEG and RG&E ratepayers.

Mitigation of vertical market power could be pursued through imposing conditions rather than requiring divestiture of wind facility ownership and a complete exit from the generation market. While Staff cautions that only separation of the T&D and generation functions is truly adequate to protect ratepayers from the exercise of vertical market power, if the Commission decides to approve the transaction, it could instead provide for procedural, process and contractual protections. Implementation of those protections, however, cannot fully eliminate the risk that Iberdrola might exercise market power to the disadvantage of ratepayers, and would require vigilant and active supervision by the Commission.

The additional procedures could include the review of vertical market power issues in proceedings conducted upon Iberdrola proposals to build specific generation facilities. Under PSL §68 the Commission must already approve any wind generation facility sized in excess of 80 MW, and, for facilities sized at 80 MW or less, Iberdrola must obtain permission, under PSL §66-c(3), to create the subsidiary that will own the wind generation facility. In addition, the Commission could require a process where Iberdrola funds independently-conducted studies of the T&D system reinforcements and upgrades needed within the NYSEG and RG&E service territories to accommodate new wind projects and avoid exercises of vertical market power. Those studies would enable Iberdrola's competitors to plan their wind projects and bring to light circumstances where Iberdrola and a competitor pursue use of the same T&D facilities.

Iberdrola also could be required to enter into contracts for the output from its wind generation facilities that disconnect its revenues from New York Independent System Operator (NYISO) market prices. This will dampen the incentive for Iberdrola to use its monopoly T&D powers to raise prices for all generation in upstate New York, just so its wind generation projects will also benefit.

These alternatives may be considered if Iberdrola is allowed to escape the obligation to furnish the tangible monetary benefits required in the KeySpan/Grid Order, and to avoid compliance with existing vertical market power policies. These remedies, however, are inferior to those Staff recommends.

SUMMARY OF EXCEPTIONS

In recommending that the Commission deny Iberdrola's petition for approval of its acquisition of Energy East, the ALJ found the benefits proffered were insufficient to meet the positive benefits test under PSL §70; that vertical market power was not mitigated; and, that structural and financial protections were inadequate to offset risks. These recommendations are firmly grounded in the facts on the record in this proceeding and long-standing Commission policies and precedents.

Although adopting most of Staff's positions, in several instances, the ALJ raised questions and asked the parties to respond with additional arguments. The ALJ also questioned Staff's analysis of the exercise and effect of VMP outside the NYSEG and RG&E service territories, and declined to resolve the rate plan issues that Staff supported with testimony, exhibits and reference to precedents.

Answers to the questions the ALJ raised are provided below. VMP is analyzed, and alternatives to wind facility divestiture and Iberdrola's exit from the generation market as the means for preventing its exercise are explored. The role of tangible monetary benefits in justifying approval of the transaction, and implementation of those benefits through new rate plans, are addressed, along with the terms and conditions that should be reflected in those rate plans.

EXCEPTIONS

Staff asks the Commission to either adopt Staff's position or alternatives Staff proposes upon exceptions to the following recommendations made in the RD:

1. On treating Iberdrola's proposal to spend up to $2 billion on wind project development over a five-year period as a benefit to ratepayers (RD 35).

2. To the alleged absence of a rationale for extending, statewide, the restrictions on Iberdrola's ownership of generation that were imposed within the NYSEG and RG&E service territories (RD 73).

3. On the analysis of the alternative proposals offered by Strategic Power Management (SPM) for mitigation of the VMP that Iberdrola's ownership of wind generation creates (RD 74).

4. On the structuring of the auction process for divestiture of existing Iberdrola and Energy East generation facilities, including the proposed allocation of 10% of the auction proceeds to shareholders (RD 77).

5. To reject some provisions of Staff's proposed Code of Conduct and Staff's proposal to hold ratepayers harmless upon credit rating downgrades, and to question other aspects of Staff's structural and financial protection measures (RD 101, 114-16).

6. On the amount of positive benefit adjustments (PBA) that should be recognized in this proceeding and the link between PBAs and Iberdrola's commitment to invest in wind projects (RD 121).

7. On the comparison of the tangible monetary benefits Staff proposes to the benefits obtained in Maine upon review of the Iberdrola transaction, and to the benefits furnished in the KeySpan/Grid merger over a ten-year period (RD 135).

8. On the analysis of the benefits Iberdrola will realize from production tax credits (PTC) for wind generation (RD 126).

9. To require a rate proceeding lasting eleven months, from implementation of the temporary rates, to determine final rates (RD 145).

10. To decline to decide the rate plan issues presented in this proceeding (RD 145).

ARGUMENT

1. Iberdrola's Proposal to Spend up to $2 Billion on Wind Project Development

From the inception of this proceeding, Iberdrola has touted its ability to develop wind generation projects within New York as a benefit to New York's electric ratepayers. In its Partial Acceptance filed on March 14, 2008, Iberdrola sought to render its wind development expertise more tangible by promising to invest $100 million in New York wind generation projects, if certain circumstances occurred (Exh. 50). Subsequently, Iberdrola has raised the purported amount of its investment to $2.0 billion.

A. Wind Investment as a Benefit

Iberdrola's alleged wind investment benefit remains speculative (SM 1191-92). The conditions Iberdrola attached to its Partial Acceptance allow it to readily escape the obligation to invest the $100 million promised there, and similar conditions would doubtless apply to its offer to invest $2 billion (RD 42-45). Even if the conditions were eliminated, however, the offer could not be readily rendered enforceable as a binding commitment. Indeed, when asked what recourse would be available if it did not meet its $100 million commitment, Iberdrola first responded only that it did not envision such a scenario (SM 673). Even when pressed, Iberdrola was unable to make a convincing argument that its promise was enforceable (SM 678-80).

Experience with similar commitments to provide non-rate benefits following consummation of other mergers underscores the difficulty of enforcement. When NYSEG and RG&E merged in 2002, promises to improve upon service quality and reliability were not kept in any meaningful way (SM 1196-97). Other promises, on the retention and location of officers and employees, representatives on the Energy East Board of Directors, the continued operation of regional customer service centers, and the promotion of community and economic development also proved unenforceable. Although those promises were embodied in a contract -- the merger agreement -- that contract did not provide for continuation of most of the obligations beyond the date the merger closed.[3] Iberdrola's promise to include similar conditions in its merger agreement with Energy East will likely prove similarly ephemeral (SM 669).

[3] Case 01-M-0404, Petition, §§7.9-7.21; §10.1.

There are other reasons for finding that Iberdrola’s offer to invest in wind generation development is not a benefit related to its acquisition of Energy East. Iberdrola maintains that its ownership of NYSEG and RG&E will encourage it to expend resources on generation development in New York rather than in other states. But Iberdrola’s own actions undermine its contention -- it is pursuing wind projects in states like Pennsylvania, Oregon and Texas, where it has no plans to own T&D utilities, but it is not pursuing wind development in Maine, where it would own a T&D company if its acquisition of Energy East is approved (Exh. 41, Att. 19; Exh. 88, Response IBER-0315, IBER-0155). It is business and economic considerations, not ownership of T&D utilities, that will drive Iberdrola’s wind investments (RD 42-47, SM 668, 677-78).

Nor is it likely that Iberdrola will forgo development of wind projects in New York, where the renewable portfolio standard (RPS) incentive is available, for states where projects are less profitable because there is no RPS incentive.[4] As to Iberdrola’s claim that its wind development expertise is needed for New York to achieve its renewable generation goals (SM 519, 836), that claim is against the weight of the evidence in this

[4] See, e.g., Case 03-E-0188, Retail Renewable Portfolio Standard, Order Approving Implementation Plan, Adopting Clarifications and Modifying Environmental Disclosure Program (issued April 14, 2005).

proceeding. Even if Iberdrola were to withdraw from the State, the loss of one developer will not detract from achieving the wind generation goals New York has set because the wind project queue is already full with other developers eager to build wind projects (RD 45, SM 862).

Therefore, Iberdrola's offer to develop wind projects should not be considered a benefit in this proceeding, and should not contribute towards its satisfaction of the PSL §70 positive benefits test needed to justify approval of its acquisition of Energy East. If, however, the Commission decides to treat wind project development as a benefit, a means of enforcement of the wind investment commitment is needed. Staff sets forth, at Exception 6 below, a proposal to tie the amount of the investment commitment to the amount of the PBAs Iberdrola should be required to furnish as the tangible monetary benefit warranting approval of the transaction.

B. The Amount of the Wind Investment Benefit

At RD 35, the ALJ asks parties to clarify their understanding of the investment Iberdrola proposes, beyond the $100 million stated in the Partial Acceptance. Although the $2.0 billion investment in wind facilities was not promised on the record here, Iberdrola did state it intends to develop 998 MW of wind capacity (Exh. 57), at a cost of about $2.0 billion, or $2 million per MW (SM 681). It appears this capacity can be subdivided into 634 MW that may become operational within the next five years, and 364 MW that is less certain (SM 696-97; Exh. 57). As a result, the $2.0 billion figure is speculative, and should be heavily discounted if relied upon as a tangible monetary benefit in this proceeding.

As to the $10 billion investment mentioned at RD 35, the source of this figure is not clear to Staff. It might include the value of the purchase price Iberdrola intends to pay Energy East's stockholders, at current exchange rates, which reflect the depreciation of the dollar against the euro.

2. Extending Statewide the Restrictions on Iberdrola's Ownership of Generation

As explained at RD 60-71, Iberdrola's proposal to own wind generation facilities as well as the RG&E and NYSEG T&D utilities violates the Commission's VMP Policy Statement. The ALJ's cogent reasoning fully supports his conclusions that "Iberdrola's vertical integration would hobble the Commission's ability to maintain competitive markets" (RD 69) and would "open the floodgates to permit [generation construction] applications completely contrary to the competition policies the Commission has expressed" (RD 70). The conclusion reached in the RD is that, if the Commission approves the transaction, it should prohibit Iberdrola and its affiliates from owning generation interconnected with the T&D facilities of the NYSEG and RG&E companies that would become affiliated with Iberdrola as a result of the transaction. That prohibition, however, is not extended state-wide, as Staff recommended. In concluding that there is no rationale for that extension of the prohibition (RD 73), the ALJ errs.

A. VMP Outside the T&D Service Territories

So long as Iberdrola owns both T&D and wind generation affiliates, there is an incentive for it to exercise vertical market power. Even if generation facilities Iberdrola owns are located outside the NYSEG and RG&E service territories, Iberdrola can use the T&D assets to raise the prices paid that generation across upstate New York, even outside the service territories.

The ALJ's focus on the NYSEG and RG&E service territories as the focus for the exercise of VMP disregards the fact that upstate New York is one market for generation. Therefore, actions within the NYSEG and RG&E service territories affect generation prices for all of upstate New York. Iberdrola's witness Hieronymus establishes that fact by his description of NYISO Zones A-E, which extend far beyond the NYSEG and RG&E service territories, as one market (SM 819-21). Moreover, VMP was found in the KeySpan/Grid Order, even though the T&D system and generator were in the same market almost all of the time (SM 1262).[5] In comparison, the NYSEG and RG&E T&D systems and Iberdrola's existing wind facilities are in the same market almost all of the time (SM 1262).

The ALJ distinguishes the KeySpan-Grid Order, maintaining that even though the T&D system and generator at issue there were in different service territories, unnamed unique factors allow the T&D operator to exercise VMP despite the generator's location outside the T&D service territory. Those factors, however, are not unique -- any action a T&D operator takes within its service territory that affects a supply market where it owns a generation facility is an exercise of VMP to its advantage and to the detriment of ratepayers generally. Iberdrola, as the owner of NYSEG and RG&E, will be able to exercise its control over their T&D systems to raise prices in the entire upstate generation market. Indeed, since all of New York is one market at least during some hours, that exercise of control could affect the entire State during those hours.

The RD itself provides a persuasive example of how such market power can be exercised. As discussed at RD 69, a failure to build that line that interconnects with cheaper supply sources in other states or in Canada will raise the price for generation not only in the NYSEG and RG&E service

[5] KeySpan/Grid Order, p. 152.

territories, but also throughout Zones A-E, and in the remainder of the State, during hours when it melds into one market. So limiting the flow of cheap electricity into New York will affect any NYISO zone where the electricity could have been delivered, not just the zones where NYSEG and RG&E are located.

As the ALJ found, this anti-competitive impact of the “transmission line that doesn’t get built” is virtually undetectable. NYSEG and RG&E can also exercise vertical market power for the purpose of raising the price across upstate New York through other means. They could discourage the construction of large generators within their service territories, thereby reducing supply and raising prices throughout Zones A-E. Any generation Iberdrola owned in those Zones outside of the NYSEG and RG&E service territories would benefit from those higher prices. Therefore, so long as Iberdrola owns both T&D and generation affiliates, it can deploy the former to manipulate the wholesale generation market to the benefit of the latter.

In limiting the recommendation to the T&D service territories, the ALJ also misunderstands the VMP Policy Statement (RD 68). Nothing in that Policy Statement indicates that utilities are permitted to own generation outside their T&D service territories. The Policy Statement does reference an example where a T&D utility owns generation on the high side of the transmission constraint, while, as Iberdrola points out, it owns generation on the low side of the Central-East transmission constraint. The VMP Policy Statement, however, is not limited to circumstances dependent upon which side of a constraint a generator is located, and the example provided in it does not establish such a limitation.

B. The Divestiture Remedy

Approval of the Iberdrola acquisition of Energy East therefore should be conditioned upon Iberdrola's divestiture of all generation in New York, including wind generation, and a prohibition preventing it from building or owning any generation in the future (SM 1420). Constraining ownership only within the NYSEG and RG&E T&D footprint is an inadequate remedy.

In light of the above analysis, the ALJ's recommendation at RD 73 is particularly troublesome. There, he allows Iberdrola to own "generation interconnected elsewhere in New York" outside the NYSEG and RG&E service territories, without limitation as to the type of generation facility, unless a limitation to "wind" generation is read into the recommendation. Since Iberdrola has already agreed to divest all of Energy East's gas-fired generation, the ALJ's recommendation could be interpreted as reversing Iberdrola's concession. Instead, the recommendation is better interpreted as allowing Iberdrola to own only wind generation outside of the

T&D utility footprint -- albeit Staff opposes the recommendation even if so interpreted.

Although requiring Iberdrola to exit the NYISO generation market entirely is the preferable remedy to the exercise of vertical market power, and achieving compliance with the VMP Policy Statement, the Commission may decide not to adopt that remedy. In that event, there are remedies more appropriate than excluding Iberdrola only from the wind generation business inside the NYSEG and RG&E service territories. Other remedies are discussed below, at Exception 3.

3. Alternative Proposals For Mitigating VMP Attending Iberdrola’s Ownership of Wind Generation

At RD 74, the ALJ describes, and asks for comments on, alternatives to divestiture of wind generation. Among those alternatives are monitoring interconnections and various forms of long-term contracts for output from any wind generation facilities and divestiture of the NYSEG and RG&E T&D assets. Procedural and process remedies, akin to monitoring, could render it more difficult for Iberdrola to exercise market power. Properly implemented, long-term contracts could dampen the incentive for Iberdrola to raise overall generation market prices, to the benefit of generation facilities it owns, through manipulation of its T&D assets. These alternatives to remedying market power should be explored further. In contrast, divestiture of the NYSEG and RG&E T&D assets would seem to undermine the rationale for the Iberdrola - Energy East transaction, would be difficult and costly to accomplish, and could redound to the detriment of consumers if transmission rates increase as a result. It should not be pursued further.

If the Commission decides that excluding Iberdrola from participation in the generation business entirely is not an appropriate remedy, then alternative measures could be considered. Those measures, however, should explicitly limit Iberdrola to ownership of wind generation. The measures would be based on the assumption -- which Staff opposes -- that the importance of wind generation outweighs vertical market power risks. As such, the measures will be based on a conditional exemption of Iberdrola's wind generation from the VMP Policy Statement, rather than the pretense that wind facility ownership cannot create VMP concerns.

A. Procedural and Process Conditions

The remedies for an exception from the VMP Policy Statement would begin with a procedural approach. As some parties propose, a project-by-project vertical market power review could be conducted upon each Iberdrola proposal to build a wind project (RD 60). That such projects sized at 80 MW or less are qualifying facilities (QF), exempt from Public Service Law regulation under PSL §2(2-b) and §2(4), does not preclude such a review. A procedural vehicle for analyzing VMP concerns in conjunction with even QF projects exists. Once Iberdrola assumes ownership of Energy East and its NYSEG and RG&E affiliates, it will become an electric corporation under PSL §2(13). As such, it may own QF facilities which are exempt from regulation, but only through an affiliate created in conformance with PSL §66-c(3).

A case-by-case process for reviewing VMP issues could be devised under that statute, as each time Iberdrola proposes to develop a wind generation project that is a QF, it could be required to seek approval for the creation of the necessary subsidiary.[6] Since this statutory structure is in place for all New York utilities, applying it to Iberdrola would not be discriminatory, and Iberdrola has said it would comply with all existing laws on wind project development (SM 676, 686-87).

As to facilities that are not QFs, Iberdrola must obtain permission to build them under PSL §68, by obtaining a Certificate of Public Convenience and Necessity. The exercise of VMP could not be excluded as an issue in a §68 review, because the public interest test for issuance of a Certificate

[6] One utility acquired an existing owner of a QF by purchase; the §66-c(3) issue was not addressed squarely in that proceeding, and it is distinguishable because Iberdrola will be developing new wind QFs instead of purchasing existing QF entities. See Case 05-E-1423, Central Hudson Enterprises Corporation, Declaratory Ruling on Acquisition of Ownership Interest in a Qualifying Facility (issued January 20, 2006).

under that statute is broad enough to accommodate any impact that could be adverse to the interests of New York ratepayers. As a result, both QF and non-QF projects that Iberdrola intends to construct could be reviewed, and VMP issues could be addressed on a case-by-case basis. If it can be demonstrated that Iberdrola has exercised VMP in any such proceeding, permission to build another wind facility could be denied.

An additional process remedy is needed to prevent Iberdrola from discouraging competitors seeking to interconnect in the NYSEG and RG&E service territories. It is particularly important to prevent bias in interconnection, because, as the record in this proceeding demonstrates, New York’s transmission facilities necessary to move wind generation may soon be over-taxed (SM 862). Indeed, one wind project proposed for New York has already raised the issue of whether the delivery of its electricity will interfere with deliveries from other sources of renewable generation.[7] A shortage of delivery system capability would create an even greater incentive for Iberdrola T&D affiliates to favor interconnection of Iberdrola generation affiliates over the generators owned by competitors.

This VMP incentive can be counteracted, but not eliminated, by establishing an independent transmission planning

[7] Case 07-E-1343, Marble River LLC, Order Granting Certificate of Public Convenience and Necessity and Providing For Lightened Regulation (issued June 19, 2008).

process, in addition to the PSL §66-c and §68 procedural remedy discussed above. Iberdrola could be required to fund a study, conducted by an independent analyst at least once every three years, of the transmission upgrades and reinforcements needed within the NYSEG and RG&E service territories to interconnect all wind power projects that are proposed. The study would also encompass transmission additions that would increase transfer capacity between adjoining states and regions, to prevent the "line that isn't built" from escaping detection.

The procedural and process remedies are crucial to achieving New York's objective for the development of wind power. They are intended, in part, to prevent Iberdrola from exercising the form of VMP known as raising rivals' costs. Through its control of NYSEG and RG&E, Iberdrola need only subtly delay the interconnection of competitors' projects, while subtly favoring interconnection of its own. Competitors would then be discouraged from proceeding with their projects (SM 1274-76). The consequence would be the loss of a vigorous market with many developers competing to build projects, which could mean the failure to develop wind generation sufficient to meet New York's goals or the payment of excessive prices for that generation.

In order to achieve its wind generation development goals, New York must remain inviting to all wind developers, and should not be seen as favoring Iberdrola. The procedural and process remedies Staff proposes above could affirm to competitors of Iberdrola that they will receive fair treatment in New York and that Iberdrola will not be favored in interconnecting its projects. Iberdrola's competitors will have an avenue to prompt consideration of any complaints they might raise if they believe vertical market power is exercised against them, and will possess the information they need to pursue interconnection of their projects.

B. Contractual Conditions

Contractual measures are needed to alleviate, to the extent feasible, the harms that would attend Iberdrola's ownership of both wind generation and NYSEG and RG&E. To mitigate the incentive for Iberdrola to deploy its control over T&D to raise market prices across upstate New York to the benefit of its generators, it should be required to enter into a contract for each wind facility that divorces the profit from the market price. These contracts could be structured as a contract for differences (CFD), which are financial devices that sets the prices that will be received for the generation independently of the market prices by providing for payments that balance to a pre-determined level the revenues generators receive from the NYISO. The term of any such contract should be at least ten years, to adequately address the incentive to raise market prices. Iberdrola affiliates should be excluded as counterparties, and contracts for existing facilities should be executed promptly.

These CFDs would dampen the incentive for Iberdrola to raise overall market prices, so that the wind generators it owns would benefit from those higher prices along with all other generators. This exercise of market power is particularly pernicious, because market prices in general would increase, affecting all of the generation that ratepayers eventually purchase at market prices. Weakening the link between the market price and the price Iberdrola would receive for its generation mitigates that incentive to some extent. As a result, the CFD contracts of Iberdrola's wind generation facilities should be required as a condition for approval of the transaction, if Staff's divestiture remedy is rejected.

Staff cautions, however, that divestiture remains the preferable remedy, that careful supervision of Iberdrola's actions to prevent the exercise of VMP will be necessary, and that even with these measures, the risk that ratepayers will pay more than they should for electricity because of the exercise of VMP cannot be eliminated. Only divestiture and exit from the generation business can accomplish that latter goal.

4. Structuring the Auction Process For Divestiture of Existing Iberdrola and Energy East Generation Facilities

Several parties to this proceeding addressed the auction process needed to implement divestiture. Among the issues raised is the incentive Iberdrola should receive out of the proceeds of the auction.

As the ALJ notes, this record offers little support for adopting an incentive (RD 78). In the past, incentives have varied widely. For example, when NYSEG auctioned its fossil-fueled generation in 1998, it received no incentive at all.[8] In contrast, Con Edison was allowed to retain the first $50 million of gain above book value.[9] Given this disparity among the applicable precedents, and the scanty state of the record in this proceeding, the ALJ properly decided that the level of incentive and other auction issues should be deferred to an auction plan collaborative conducted after a decision is reached on the transaction itself (RD 78).

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[8] Case 96-E-0891, New York State Electric & Gas Corporation, Order Authorizing the Process For the Auctioning of Generation Plant (issued April 24, 1998), p. 2.

[9] Case 96-E-0897, Consolidated Edison Company of New York, Inc., Order Authorizing the Process For Auctioning of Generation Plant (issued July 21, 1998).

5. The Rejection of Some Provisions of Staff's Proposed Code of Conduct and Questioning of Other Protective Measures

Because Iberdrola's acquisition of Energy East creates additional risk to ratepayers, Staff proposed changes to the existing Code of Conduct between Energy East and NYSEG and RG&E. An enhanced Code of Conduct, as set forth at Exhibit 111, is necessary to address the fact that Iberdrola is a much larger and more diverse entity than Energy East. Consequently, both the variety of affiliate transactions and the magnitude of the harm they may cause regulated ratepayers increases with the addition of Iberdrola to the ownership structure as the parent of the existing Energy East holding company.

Iberdrola's approach to the code of conduct is to "step into the shoes" of Energy East (RD 88). It appears that Iberdrola means by this that it would retain the existing Code of Conduct, but would substitute itself for Energy East wherever restrictions on holding companies are present in the existing Code.

The ALJ rejected Iberdrola's position and, except for two issues concerning affiliate restrictions and protection from rating downgrades, decided that Staff's Code of Conduct should be adopted. Iberdrola, however, was offered the opportunity to challenge any additional conditions Staff proposed, by demonstrating the provision was burdensome to them and was not reasonably commensurate with alleviation of the risk that would be remedied (RD 113-15). The ALJ also noted some confusion upon this record regarding the Code of Conduct. That confusion occurs primarily because Iberdrola did not raise its objections to Staff proposals until filing its Reply Brief in this proceeding. Although Staff was unable to respond to that Reply Brief at the time, many of Iberdrola's arguments were premised upon typographical errors in Exhibit 111 that could have been clarified had Iberdrola noted its objections earlier.

A. Affiliate Relationships

In deciding the first of two Code of Conduct issues he raised, the ALJ rejects Staff enhancements consisting of two different provisions. First, Staff proposes, at Standards of Conduct §(i), that no affiliate could use the Energy East, NYSEG or RG&E name. Second, at Affiliate Relations §(5)(c), Iberdrola affiliates are prohibited from providing services to Energy East, NYSEG or RG&E.

As to the restriction on affiliate names, it prevents any affiliate from using the Energy East, NYSEG or RG&E reputation to clothe themselves with the level of trust the public places upon regulated entities. Any of Iberdrola's vast web of affiliates must be prevented from confusing the public through such means. This sort of protection is needed, given the lack of control Iberdrola has exhibited over some of its subsidiaries, including its failure to realize that violations of the existing Code of Conduct would be committed when it added NYSEG and RG&E to its stable of affiliates that already included Community Energy, Inc. (which has an exclusive green power marketing arrangement with NYSEG and RG&E)(SM 1362-64; Exh. 88, Response IBER-0071S).[10]

This enhanced provision would require Iberdrola to change the name of NYSEG's existing energy services company (ESCO) affiliate, NYSEG Solutions, Inc. Such an outcome is a necessary consequence of the restrictions needed in face of the complexity Iberdrola brings to the existing Energy East holding company structure (SM 1180-82; Exh. 20, Response IBER-0295, Exh. 42, Response IBER-60). RG&E already does quite well with an ESCO affiliate, Energetix, that does not share its corporate name, and requiring NYSEG to do likewise is not burdensome or inappropriate.[11]

As to the restriction preventing Iberdrola affiliates from providing services to Energy East, NYSEG and RG&E (RD 107), Iberdrola's position in this proceeding compels that result. Iberdrola claims that there will be no synergies between it and

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[10] If the transaction is approved, Iberdrola should be directed to bring the NYSEG and RG&E relationship with Community Energy, Inc. into conformance with the Code of Conduct within 60 days of the approval.

[11] If Staff's argument is rejected, a royalty for use of the name should be imputed in rates (SM 1430).

the regulated New York companies (SM 936), in part because NYSEG and RG&E already obtained services from Energy East subsidiaries, and so looking to other Iberdrola affiliates for those services would be duplicative. For these reasons, holding Iberdrola to the position it asserts, by preventing it from providing services, is reasonable.

This restriction, however, is not in any way interpreted as affecting Iberdrola's authority to engage in transactions with its subsidiaries that do not involve Energy East subsidiaries. The restriction is clearly limited to relationships between Iberdrola and Energy East only, not to other relationships. Therefore, the interpretation Iberdrola hypothesizes is incorrect.

On the other hand, this restriction does not prevent Energy East from providing services to Iberdrola even though services from Iberdrola to Energy East are prohibited. As a result, synergies may flow from Energy East to Iberdrola. Those synergies should be captured through the tangible monetary benefit Staff discusses in Exception 6.

Restricting the flow of services to only one direction, from Energy East to Iberdrola, is entirely appropriate. Staff can audit the limited universe of the services Energy East would provide from the two existing service companies Energy East operates. The extensive universe of

Iberdrola affiliates that might provide services to Energy East, however, could never be properly audited (SM 1180-82).

In one other respect, not specifically mentioned by the ALJ but similar to the new conditions discussed above, the Code of Conduct is enhanced to allow Staff to audit any Iberdrola affiliate. This provision, at Access to Books and Records and Reports, §(i)(a), is also necessary. If discrepancies are discovered upon the books of Energy East that appear to implicate Iberdrola affiliates in violation of standards of conduct, Staff must be able to pursue that violation to its source, at the Iberdrola affiliate. Denying that ability may prevent Staff from obtaining a complete picture of any suspicious transaction, thereby hampering its ability to protect ratepayers.

B. The Hold Harmless Provision

The ALJ also rejects a second Staff proposal that NYSEG and RG&E customers be held harmless with any increased cost of capital that results from the downgrade of a credit rating of those companies (RD 115). The ALJ maintains that the provision would be difficult to enforce, because it would be difficult to ascertain the cause of a downgrade and whether that cause warranted the proposed hold harmless remedy. Staff, however, did not propose that an inquiry into causation be conducted.

Instead, the hold harmless conditions should be triggered automatically if NYSEG or RG&E are downgraded. The de-rating alone is sufficient to justify the hold harmless remedy, without launching an investigation into causation, based on the principle that ratepayers should not suffer whatever the cause of a rating downgrade. So protecting ratepayers is a practical remedy that places the onus for maintaining the operating companies' financial health where it belongs -- on the parent company. The provision ensures that ratepayers will not suffer as a result of the Iberdrola transaction, and presents an incentive for Iberdrola to safeguard the operating companies' financial health or promptly remedy any downgrade. As a result, the condition should be adopted.

C. Indirect Loans

The ALJ, at RD 101, also asks for a definition of the indirect loans that are needed to effectuate Staff's proposed conditions limiting money pool transactions. Money pools must be strictly supervised, because they lump together in one debt transaction subsidiaries of varying financial strengths and differing interests. An indirect loan can circumvent the restrictions on money pool transaction. It occurs when a subsidiary makes loans to a parent, and the parent then loans that debt to another subsidiary participating in the money pool. During the course of the transfer to the second subsidiary, the conditions of the loan might change, circumventing the restrictions on money pool transactions that would otherwise adhere to all subsidiaries participating in that pool. As a result, indirect loans should be prohibited.

D. The Typographical Errors

The RD repeats Iberdrola's allegations, from pages 37-38 of its Reply Brief, that errors and inconsistencies prevent adoption of Staff's Code of Conduct. Those errors, however, consist mostly of typographical errors that could have been corrected had Iberdrola brought them to light earlier.

These errors are easily corrected. Under Personnel §(4)(f) there is a reference to the compensation of Energy East officers who are also officers of NYSEG and RG&E. That conflicts with Personnel §(4)(c), which prohibits Energy East officers from serving at NYSEG or RG&E. The inappropriate reference is merely typographical, and may be readily deleted.

Similarly, Personnel §(4)(d) reads poorly only because of typographical errors consisting of a missing word and extraneous periods and misplaced commas. It is readily corrected to read "After that, the DISCO will be entitled to compensation...."

Personnel §(5)(c) contains a reference to "chaining transactions." That reference again is a typographical error and may be deleted. Chaining transactions need not be addressed in the Code of Conduct, because, if Staff's proposed prohibition against the provision of services by Iberdrola affiliates to Energy East affiliates is adopted, chaining transactions cannot occur. The financial conditions of approval Staff proposes, at Condition 32, contain a prohibition against chaining transactions, which should be adopted if Staff's proposed prohibition is not (RD 106; SM 1234-36).

Iberdrola also objected to other enhancements to the Code of Conduct related to credit quality goals, dividend restrictions, money pools, and the like. All of these restrictions are justified in the financial and structural protections that the ALJ adopted. Reaffirming them in the Code of Conduct, besides including them as ordering clauses conditioning this transaction, enhances their enforceability, but does not otherwise affect their content.

E. Conclusion

As a result, Staff's Code of Conduct should be adopted as proposed, with typographical errors corrected. If it is decided that the Code of Conduct could benefit from a more thorough effort and careful drafting, Staff could be required to submit a revised Code of Conduct as a compliance filing to the Order issued in this proceeding. Parties would then be permitted to file comments on the compliance filing, and the Commission could decide any remaining issues.

6. The Amount of Positive Benefit Adjustments Recognized in This Proceeding and the Link to Iberdrola's Investment Commitment

The ALJ properly recommends that the Commission adopt the full amount of Staff's PBAs, and require Iberdrola to implement $646.4 million in rate modifiers at NYSEG and RG&E, reducing the rates customers pay for regulated delivery service (RD 117-18). The process for implementing a PBA adjustment to NYSEG and RG&E rates, however, is addressed at RD 144-45. There, the ALJ recommends that, if the transaction is approved upon conditions, rates be made temporary immediately, while recognizing the 4.4% overall rate reductions arising out of the $201.6 million in PBAs Iberdrola has already offered in this proceeding. The effect of any remaining PBAs the Commission might direct would be reflected after rate proceedings for NYSEG and RG&E are conducted.

Staff proposes an iteration to this process for implementing the PBAs. As discussed above, Staff opposes recognizing Iberdrola's potential investment of $2.0 billion in wind generation facilities in New York as a benefit in this proceeding, because the offer cannot be enforced and the benefit is consequently ephemeral. If, however, the Commission wishes to recognize the proposed $2.0 billion investment as a benefit, that benefit should be rendered concrete, through a binding obligation. This can be accomplished by tying the level of wind generation investment to the level of PBA adjustments required in this proceeding, with PBAs increasing if Iberdrola fails to make its promised investment.

One approach would be to require Iberdrola to place the value of its wind investments in a PBA account for the benefit of customers. The value of the account would not be set at the $2.0 billion that Iberdrola says it could invest. Some of that investment would take place even in the absence of the purchase of Energy East; as Iberdrola has stated, it pursues investments that make economic sense (SM 678). As a result, it will undoubtedly build some wind projects in New York even if the proposed transaction is not approved. On the other hand, extraneous conditions, like the availability of the PTC, the RPS incentive, and economic conditions generally may reduce Iberdrola’s desire to invest. Moreover, Iberdrola might also displace the investment other developers would make. As a result, discounting the $2.0 billion amount is appropriate.

For example, the Commission could discount the value Iberdrola’s plans to build 1,000 MW of wind projects to $200 million, instead of $2.0 billion. The $200 million amount could be set aside in a PBA account. For each MW of wind generation Iberdrola then builds in New York, the PBA account would be reduced on a pro-rata basis by $200,000. Should Iberdrola build out its entire 1,000 MW plan, the PBA account would fall to zero. If, on the other hand, Iberdrola failed to bring any new projects on line, the $200 million in the PBA account would inure to ratepayers at a future time. The accounts could also be structured to provide for draw-downs as each Iberdrola project enters service.

By these methods, Iberdrola's proposal to make wind generation investments can be made real for New York. If Iberdrola actually invests the amounts promised, the investment would be treated as a benefit. If it fails to make the investment, an offset in the form of lower rates compensates ratepayers for the default, and ensures they receive the value they are entitled to under the §70 positive benefits test.

The first decision the Commission would make in implementing one of these approaches would be to select an initial level of PBAs for immediate recognition in rates. For the reasons discussed in the RD, as supported by the record in this proceeding, Staff believes that the $201.6 million Iberdrola offers is inadequate. Moreover, the value of that figure is dependent upon its reflection in rates as of July 1, 2008, and so the value of the offer decreases upon implementation later than that date (SM 1457).

Therefore, the Commission should first consider is the actual value of Iberdrola's offer as of the date rates become temporary. It must then decide what initial PBAs should be recognized upon the institution of temporary rates, and what PBAs should remain open for implementation at the conclusion of the rate proceeding the ALJ recommends (subject to Staff's proposed modifications to that process discussed below at Exceptions 9 and 10). The level of PBAs that should be contingent upon Iberdrola's actual level of investment in wind generation projects would then be decided. These issues are discussed further below, at Exceptions 9 and 10.

7. Comparisons of the Tangible Monetary Benefits Staff Proposes to the Benefits Required in Other Transactions

A. The Maine Transaction

At RD 138, the ALJ opines that Staff did not properly compare the benefits Iberdrola offered in pursuing approval of the acquisition of Energy East in Maine to the benefit offered here. The ALJ adopted Iberdrola's argument that those benefits amounted to only 3.3% of the delivery rates of Central Maine Power Company (CMP), Energy East's Maine T&D subsidiary.

As the ALJ analyzed Iberdrola's argument, CMP did not seek to recover the $306 million acquisition premiums paid in Maine, because, in settlement, it agreed to pursue recovery of only $8.8 million. As for the $86 million advanced metering initiative (AMI) benefit Staff ascribed to the Maine transaction, the petitioners claimed that benefit was worth only $1.6 million annually.

Because Iberdrola in Maine acquiesced to recovery of only $8.8 million of the acquisition premium, the remainder of the $306 million that was forgone is a benefit of the transaction. Iberdrola claims it could not have obtained that amount, but relies primarily on the Maine Bench Analysis, at Exhibit 53, where its argument on recovery of the acquisition premium was rejected. While many of its other positions were rejected in the Bench Analysis, Iberdrola did not acquiesce to their rejection. Therefore, its surrender of the acquisition premium was a benefit of the Maine transaction, and should be counted in the analysis.

Moreover, Iberdrola has failed to support its analysis of the annual AMI benefit at $1.6 million. That number is absent from this record; instead, Iberdrola had the opportunity to quantify the annual AMI benefit on the record, but it declined (SM 592-93). The $86 million overall value for AMI that Staff relies upon, however, is on the record (SM 1486). That amount translates to $3.7 million on an average annual basis, not Iberdrola's $1.6 million.

When the correct annualized value of the forgone acquisition premium is combined with the annual AMI benefit, the actual benefit amount realized for ratepayers in the Maine proceeding is $12.5 million annually, compared with CMP delivery revenues of $223 million annually (Iberdrola Reply Brief, p.

108, fn. 134). This calculates to 5.6% of CMP's revenues, not the 3.3% Iberdrola alleges.

B. The 10-Year KeySpan/Grid Comparison

At RD 136, the ALJ posits that merger benefits over a 10-year period are more relevant than an estimate of the benefits over an initial 5-year period. The ALJ suggests that a comparison of KeySpan/Grid benefits over a 10-year term to comparison of the benefits here over a 10-year term would be valuable.

Staff performed such an analysis during the course of this proceeding, in response to an Information Request from Iberdrola. That analysis is set forth at Staff Response IBER/EE IR No. DPS-83. A copy is attached at Appendix A. The comparisons demonstrate that Staff's PBAs here yield benefits equating to approximately 5.1% of the delivery revenues of Energy East's New York subsidiary, when the comparable figure for the KeySpan/Grid merger is approximately 5.9% of delivery revenues. Again, these figures demonstrate that Staff's proposed PBA adjustment is reasonable.

C. Comparison of Staff and Iberdrola PBAs

On an annual basis over a five-year period, Staff's PBAs yield a reduction of 7.6% to the NYSEG and RG&E delivery revenues. Iberdrola claims a 4.4% annual reduction for its $201 million in PBAs. The greater impact of Iberdrola's PBAs result from the fact that many of them affect both expense and rate base, whereas some of Staff's PBAs are directed solely to rate base. A reduction to rate base does not reduce current rates to the extent that a reduction to expense does. These sorts of effects can be addressed when PBAs are implemented in the rate proceeding the ALJ proposes, subject to Staff's modifications to that process, as discussed in Exceptions 9 and 10.

8. Analysis of the Benefits Iberdrola Will Realize From Production Tax Credits

At RD 128, the ALJ notes that Staff's estimate of $150 million in PTCs that Iberdrola will acquire in 2008 is overstated by $50 million attributable to PTCs earned by projects that pre-existed the acquisition transaction. Staff developed the PTC calculation by multiplying Iberdrola's estimate of its wind production 2008 times the PTC credit of 1.9¢ per kWh. Iberdrola's production estimate concededly included generation from existing facilities, which translate into a value of $50 million of the $150 million in 2008 PTCs.

Nonetheless, the benefit of PTCs to Iberdrola remains understated. Staff's $150 million estimate was for the year 2008 only, while PTCs remain available for ten years on each wind project Iberdrola develops. As a result, Iberdrola can expect to earn PTCs well into the future beyond 2008; at a level of $100 million per year, the total would reach $1.0 billion. Therefore, PTCs remain a significant benefit of this transaction to Iberdrola, even if Staff's calculation of $150 million in new PTCs for 2008 is overstated by $50 million.

9. Requiring a Rate Proceeding Lasting 11 Months From Implementation of Temporary Rates to Determine Final Rates

The rate plans for NYSEG gas, RG&E electric and RG&E gas expire on December 31, 2008.[12] A rate plan is not currently in effect for NYSEG electric, but its rates were re-set in 2006 in the NYSEG Electric Order.[13] In compliance with the RG&E Rate Plan Order, RG&E has filed, on February 1, 2008, a request to continue its Rate Plan beyond its December 31, 2008 expiration date. Moreover, the rate plans contain provisions that allow the Commission to act should the rates become unjust or unreasonable.[14]

If the transaction is approved, the ALJ proposes that NYSEG and RG&E rates be made temporary immediately, and that an 11-month proceeding be conducted thereafter to arrive at

[12] Case 03-E-0765, et al., Rochester Gas and Electric Corporation – Rates, Order Adopting Provisions of Joint Proposals With Conditions (issued May 20, 2004) (RG&E Rate Plan Order); Case 01-G-1668, New York State Electric & Gas Corporation – Gas Rates, Order Establishing Rates (issued November 20, 2002) and Order Concerning Rate Design, Economic Development, and Affordable Energy Programs (issued September 23, 2004)(NYSEG Gas Order).

[13] Case 05-E-1222, New York State Electric & Gas Corporation, Order Adopting Recommended Decision With Modifications (issued August 23, 2006).

[14] NYSEG Gas Rate Joint Proposal, §XXXI.7.b.; RG&E Electric and Gas Rate Joint Proposals, §§XXII.6.b.

permanent rates (RD 145). Temporary rates are necessary at some point in any event, because, as the ALJ noted, NYSEG and RG&E are overearning.

Staff supports the ALJ's conclusion on overearnings (SM 1741-42, 1679-80). Based on the most recent ACFs Staff has received,[15] NYSEG's electric operations have earned 17.18% for the years 2002 through 2006,[16] and its gas operations have earned 10.12% for the years 2002 through 2007, on average. For RG&E, electric operations have earned 13.05% for the years 2004 through 2007 and its gas operations have earned 9.16% on average for those years. Given Staff's position, discussed below at Exception 10, that an ROE of 9.0% is currently reasonable, these returns are excessive. Moreover, if PBAs are reflected in the analysis, the returns will become even more excessive.

A. <u>The ALJ's Temporary Rate Process</u>

To address these overearnings, and to rapidly implement at least some PBA benefit, the ALJ proposes to make rates temporary immediately, if the transaction is approved, upon a 4.4% overall rate reduction to NYSEG and RG&E ratepayers.

[15] NYSEG and RG&E, under their respective Rate Orders, make Annual Compliance Filings (ACF) detailing deferrals, reserve changes, and reconciliations performed in accordance with the applicable Rate Order. These filings are usually submitted within 90 days after the close of the previous calendar year.

[16] NYSEG was not required to file a 2007 ACF for electric operations because its electric rate plan expired and was superseded by the NYSEG Electric Order.

Iberdrola has agreed to a rate reduction of that amount albeit based on the value of its PBAs as of July 1, 2008 (Exh. 50). As the ALJ states, this approach provides some immediate rate relief from excessive rate levels, and commences the process of recognizing PBAs in rates while additional PBA and regulatory adjustment issues are addressed subsequently. The ALJ would structure that subsequent proceeding as a major rate filing with an 11-month suspension period.

Staff agrees that making rates temporary at a 4.4% rate reduction, as the ALJ recommends, is an appropriate remedy. The exact level of PBAs necessary to achieve that rate reduction could be determined later, in conjunction with the level of any additional PBAs the Commission requires, as discussed above at Exception 6. Staff would not, however, embark upon an 11-month major rate filing process.[17]

Traditional major rate filing proceedings are often adversarial, focused on short-term issues such as forecasting a single rate year, and do not address incentive-based solutions to long-term complexities that may confront a regulated utility. Moreover, if the transaction is approved, Iberdrola and Energy East must rapidly combine into an effective holding company entity. Prosecuting a major rate filing would be a distraction

[17] Should the Commission reject this remedy, priority should be given to action on RG&E's rates, as it is overearning to a greater extent than NYSEG.

from that effort, especially because the filing would affect four utility operations -- NYSEG electric and gas and RG&E electric and gas. As a result, an alternative to a major rate filing should be found.

B. The Staff Rate Plan Process

A better approach would be to decide here the rate case issues presented on this record, as set forth at Exception 10. Then, an expedited rate process could be used to set new rates that would replace the temporary rates as soon as feasible.

To accomplish this goal, streamlined filing requirements should be established. Streamlining a rate filing is not foreign to Energy East. In 2001, NYSEG sought to extend an existing rate plan without making a major rate filing. The Commission decided that NYSEG's request could be reviewed without the detail a major rate filing would entail, but, nonetheless, that some substantial level of information was required.[18] The Commission then ruled on the information template that would be adequate.[19] A similar process should be successful here, and enable the parties to focus attention on

[18] Case 01-E-0359, New York State Electric & Gas Corporation, Order Clarifying Data Required (issued April 25, 2001).

[19] Case 93-G-0932, Restructuring the Emerging Natural Gas Market, Order Clarifying Gas Policy Statement (issued April 1, 1999).

the policy issues discussed in Exception 10 instead of litigating minutia.

Staff therefore proposes NYSEG and RG&E each prepare a filing of financial projections for the four year period (2008-2011) within 45 days of any approval of the transaction. The filing, which would be less rigorous than the requirements for a major rate filing, would include the following:

(1) For both NYSEG and RG&E, the companies will provide financial results for the twelve months ended December 31, 2007. For revenues and expenses, the historic data should be by major accounts and major cost components, respectively. For taxes, the historic data should be segregated between federal income taxes, gross receipts taxes, property taxes and other taxes. For rate base, the historic data employed by the Commission in the 2006 NYSEG Electric Order should be in the format.

(2) Projections for the twelve months ended December 31, 2008, December 31, 2009, December 31, 2010 and December 31, 2011. For revenues and expenses, the projections should be by major accounts and major cost components, respectively. For taxes, the projections should be segregated between federal income taxes, gross receipts taxes, property taxes and other taxes. For rate base, projections should be similar in the format employed by the Commission in the 2006 NYSEG Electric Order.

(3) For each forecasted rate year, a forecast of capitalization, including a statement of cash flows, long-term debt costs, short-term debt balances, external financing requirements, and projected capitalization ratios for NYSEG, RG&E, Energy East, and Iberdrola.

All forecasts should be developed from the twelve months ended December 31, 2007. For most items of the forecast, adjustments should be made to the historical base to arrive at the forecast levels with all assumptions fully explained and shown separately. Such adjustments should contain details as to changes in prices and activity levels as well as adjustments to normalize major unusual or non-recurring historical data. To the extent possible, these projections should be in a format that will permit comparisons with data for previous years.

While this filing requirement does not strictly adhere to major rate case protocols, it should provide a sufficient basis for evaluating the company's future financial results and the setting of new rates. This proposed lessening of filing requirements recognizes not only the fact that NYSEG and RG&E will be in the state of transition if the transaction is consummated but also the fact that both companies are in the final years of multi-year rate plans (except for NYSEG electric).

With these streamlined informational requirements in place, and the rate case issues presented in this proceeding decided as discussed in Exception 10, Staff and the parties could proceed to negotiate sensible rate plans in a time likely less than the 11-month rate proceeding the ALJ envisions. If the parties cannot reach agreement, competing proposals can be presented to an ALJ, who can present them to the Commission, again, in a time likely less than the 11-month period the ALJ envisions. Staff therefore proposes this process as an alternative to the ALJ's major rate filing process.

10. Deciding the Rate Plan Issues Presented in this Proceeding

In the KeySpan/Grid Order, the Commission made determinations affecting the development of rate plans for the T&D utilities that were being acquired as a result of the merger transaction under review there.[20] The Commission should make similar determinations here, notwithstanding that the ALJ declined to do so (RD 145).

The ALJ would defer consideration of rate plan issues to his 11-month rate proceeding conducted upon the conclusion of this proceeding. Staff excepts. Moreover, even if rate plan issues are not decided generally, some rate plan issues should be made a condition of approval of the transaction and a decision should not be delayed until later. If these issues are not decided, ratepayer interests could be substantially harmed.

In particular, service quality issues and the configuration of RG&E's fixed-price offer (FPO) for electric service must be decided now. In the KeySpan/Grid Order, the Commission recognized that an acquirer like Iberdrola will find it convenient to cut costs in order to make good on its investment, even if the cost-cutting adversely affects the

[20] KeySpan/Grid Order, p. 156.

quality of service the regulated utility it has purchased provides. To counteract that incentive, enhanced service quality measures are imperative. Staff proposed such measures in conformance with those adopted in the KeySpan/Grid Order. They should be adopted here as well, to take effect beginning with the 2009 calendar year.

As to the RG&E FPO offer, it is overpriced. NYSEG's FPO offer was recently revised to prevent its overpricing, and the RG&E FPO should be conformed to the NYSEG FPO. Since a new price under the FPO commences January 1, of each year, and the sign-up period for the FPO begins as of October 1, of each year, action on FPO issues is needed soon. The Commission should either decide the FPO issues for RG&E in this proceeding, or direct that the issues be brought to it for its consideration by September.

A. Service Quality Measures

As the KeySpan/Grid Order provides, metrics for the quality of electric reliability, gas safety and customer service performance has become a common feature of rate plans in place for a majority of the State's electric and gas utilities.[21] Those features were present in the KeySpan/Grid proposals for justifying approval of their merger. The Commission, however, found that the initial proposals presented by the parties

[21] KeySpan/Grid Order, p. 143.

supporting that merger were insufficient in one important, material respect. National Grid's acquisition of KeySpan, similar to the proposed Iberdrola acquisition of Energy East, posed significant financial risks to ratepayers.[22] The Commission was concerned that those financial risks could translate into incentives to undermine service quality, as spending on preserving that quality of service was sacrificed to the goal of meeting the financial exigencies of the holding company parent.

As a result, the Commission doubled the rate adjustments the parties proposed for any failure to satisfy the service quality metrics. Moreover, it ruled that the rate adjustment assessment should be tripled during any year where a dividend restriction was triggered and a metric was not met. The amount would be quadrupled for any year in which, after a failure to meet a metric in any two of the prior four years, that metric was again missed. Finally, the Commission also stressed that it would review the metrics themselves in the rate plans that it required be developed promptly after the merger was approved.

Staff in this proceeding has presented updated metrics and rate adjustments supporting those metrics that could be

[22] Because of the financial risks the transaction posed, National Grid, as well as the KeySpan T&D companies, was required to adopt enhanced assessments and metrics.

included in rate plans for NYSEG and RG&E. As is common to such rate plans, the metrics address electric service reliability, gas service safety and reliability, and customer service performance.

1). Gas Safety and Reliability

Consistent with the KeySpan/Grid Order, Staff proposed new rate metrics for NYSEG and RG&E gas safety and reliability, using basis point rate assessments that approximately reflect those required in the KeySpan/Grid Order. These higher assessments are needed because Iberdrola’s acquisition of Energy East creates incentives for the parent to squeeze capital out of the New York subsidiaries by cutting operational costs, even when the cost reductions might adversely affect safety and reliability (SM 1837-38).

As to the metrics, Staff derived them from historical performance data and forecasts of expected future capabilities (SM 1836). As is common to gas safety and reliability measures at other utilities, Staff established metrics for the replacement of leak-prone pipe and leak-prone gas services; for leak management, by setting targets for achieving year-end backlogs of total leaks; for the prevention of excavation damages (divided into categories of overall damages, damages due to mis-marks when responding to one-call tickets requesting the identification of buried gas piping, and damages caused by utility crews and contractors); and, responses to gas emergencies, measured by the percentage of calls responded to within specified time frames (SM 1802-39).

a. The NYSEG and RG&E Response

In response, the companies complain that Staff's proposed enhancements are unnecessary and unfair. NYSEG and RG&E maintain that they are ranked among the top performers in New York in virtually every gas safety category, and that their performance has improved significantly over the last five years. They also claim that Iberdrola's acquisition of Energy East will improve the performance of NYSEG and RG&E, as they will benefit from the new parent's expertise (SM 207-208).

The NYSEG and RG&E gas safety presentation is riddled with inconsistencies. On one hand, they claim that Iberdrola's global experience and expertise will improve their performance (SM 253), but on the other hand they also insist that their commitment to high performance levels "will not change after the proposed transactions" (SM 120). The companies were also unable to explain exactly how Iberdrola's acquisition would lead to improvements in their performance (SM 245-47). Nonetheless, they concede that rate assessments encourage utilities generally to achieve compliance with their metrics for gas safety, which benefits customers (SM 246, 250).

Other contradictions undermine the NYSEG and RG&E gas safety testimony. They claim that they are the only local distribution companies (LDCs) in the State that, in 2006, were not required to self-assess their performance and draft action plans on improving that performance (SM 207). But that statement is incorrect, because at least two other LDCs were not directed to participate in the self-assessment process (SM 229). The petitioners also could not arrive at the correct number for gas services replaced at NYSEG during 2005, providing at least three different figures for that year (SM 240-41, Exh. 18, Exh. 22).

NYSEG and RG&E also complain that Staff would have them increase capital spending on gas safety by $1.6 million per year, when that figure does not include capital costs for a significant increase in service replacements, and does not account for the costs of replacing pipe "as required for highway projects" (SM 212-13). When it was pointed out to the companies that Exhibit 18, page 2 of 40, clearly showed that the costs of incremental service replacements was included, the LDCs had no response (SM 232-33).

In addition to wrongly contending that Staff failed to account for the costs of highway-related projects, the LDCs' presentation on this point is so confusing as to lack credibility (SM 230-37). The confusion begins with the discrepancies between the “miles of pipe replaced” as listed in their testimony (SM 210), and the figures “miles of pipe replaced” as listed at Exhibit 18, page 7 of 40. The companies explain that “miles of pipe replacements related to highway projects” are not included in the testimonial numbers. They contend, however, that those “highway project pipe miles” are included in the Exhibit 18 figures. Notwithstanding that they say the “highway replacement project miles” are included in that Exhibit 18, they then deny that “highway project costs” are reflected in Exhibit 18 (SM 230-35). Since it is the companies that initially provided all of the underlying data in Exhibit 18 (see Exh. 19, Response IBER-0194), it was their responsibility to include “highway project costs” in that data as well as “highway project pipe miles.” Why they did not do so is not explained.

The LDCs also assert that Staff is wrong in asserting that the companies’ performance in the damage prevention metric slipped during 2007 as compared to 2006 (SM 217-18). They hypothesize that additional construction in 2007 carried with it increased opportunities for damages. One-call ticket data, however, undermines their contention. Comparing the one-call tickets for 2006, as provided at Exhibit 18, page 36 of 40, to the 2007 one-call data from Exhibit 24, shows that one-call tickets for the two companies actually declined, from 117,890 for 2006 to 116,483 for 2007. As a result, the deterioration in performance cannot be traced to an increase in one-call activity. Exhibit 24 also shows that RG&E's total leak backlog increased during 2007 as compared to 2006.

b. Staff's Development of its Metrics

Two factors therefore affect Staff's increased targets for the various service quality metrics. On one hand, Staff recognizes the improvements in performance that NYSEG and RG&E have made over the past five years. It is those levels of performance that are the basis for the metrics, not, as the company claims, the metrics from NYSEG and RG&E gas rate plans that are now five years old. Since, as the companies concede, they should constantly strive to improve their gas safety performance, metrics and targets from dated rate plans are no longer relevant (SM 213).

On the other hand, 2007 performance as compared to 2006 indicates that slippage in company performance may occur. Moreover, because Iberdrola's acquisition of Energy East creates many incentives for poor performance, the threat to gas safety performance is heightened. As a result, the gas safety metrics and rate adjustment assessments Staff proposes should be adopted.

2). Customer Service Performance

Another essential element of service quality is customer service performance. NYSEG’s current metrics for that measure are categorized into an overall customer service satisfaction index, a contact satisfaction index, and the PSC complaint rate. The satisfaction index is measured through an annual survey of a representative sample of customers in the utility’s service territory. The contact index is based on a monthly survey NYSEG conducts. The PSC complaint rate is the average annual rate of monthly complaints to the Commission per 100,000 customers. In 2006, NYSEG incurred a rate adjustment for failure to meet the contact index metric.

RG&E’s service quality measures consist of six measures: the PSC complaint rate; the customer interaction service index; appointments kept; calls answered within 30 seconds; billing accuracy; and, estimated meter readings (SM 1875-76, SM 1877-78). In 2006, RG&E failed to satisfy the metric for calls answered within 30 seconds.

Staff proposes that the service quality measures for NYSEG and RG&E be made more consistent with each other. To achieve this goal, the measures currently applicable to RG&E should be applied to both companies. Moreover, a new measure, Escalated Complaint Response Time (ECR), should be added to both companies’ measures. This latter measure captures the average number of days each utility needed to respond to escalated complaints made to PSC Staff. Escalated complaints are those that the utility failed to satisfy after initial referral from Staff (SM 1878-80).

Staff's proposed metrics are set forth at Exhibit 136. Staff would also double the current rate adjustment assessments for failure to satisfy the new metrics, consistent with the KeySpan/Grid Order (SM 1880-82).

NYSEG and RG&E complain that Staff's rate assessments are excessive (SM 130-33). They assert that they are among the better performers in service quality among New York's utilities. They dismiss their failure to meet some metrics in 2006, saying that implementation of a new customer information system inevitably led to a deterioration in those metrics, as the mistakes accompanying introduction of any new system were corrected (SM 123-26).

Staff's rate assessments, however, are justified by the Commission's decision in the KeySpan/Grid Order. Nothing the companies have submitted warrants reaching conclusions contrary to those in that Order, or countermands Staff's contention that Iberdrola's acquisition will create incentives for the deterioration of those performance metrics. As to the metrics themselves, the companies overstate their past performance, glossing over the metrics they have failed.

Staff’s metrics are needed to create an incentive for the level of customer service performance commensurate with the quality of service customers deserve.

Although the companies oppose the introduction of the new ECR metric, it is appropriate for Staff to propose such measures at any time. The metric was fully justified by Staff’s testimony. It should be adopted.

The companies also oppose setting metrics for each other at the same levels. They maintain that, even though they are both subsidiaries of Energy East, their operations remain sufficiently separate to justify separate metrics (SM 128-29). Use of the best-available metrics, however, is appropriate for any utility, unless deviations are justified. The companies have presented no such justification.

Staff proposes that NYSEG and RG&E enhance their reporting of customer performance measures, in particular by submitting an annual report on contact satisfaction surveys. NYSEG and RG&E oppose the additional reporting requirement as unduly burdensome (SM 126-27). Staff has justified the additional requirement, because it is needed to alert Staff to any degradation of customer service (SM 127, Exh. 118). The requirement should be adopted.

3). Electric Reliability

Staff proposes to continue the existing reliability performance mechanisms in place at NYSEG and RG&E, making no changes to the existing metrics and targets (SM 1856-59). Staff would, however, increase the revenue assessments for failing to achieve the targets in accordance with the KeySpan/Grid Order, by doubling the level of the assessments. If, in any year subsequent to a year in which a target is missed, the target is again not satisfied, the applicable rate adjustment would be doubled again for that year (SM 1859).

The electric reliability metrics and targets in Staff's electric reliability performance mechanism are similar to those in place at all of New York's major electric utilities. NYSEG and RG&E do not oppose the metrics and targets, although they correctly point out that NYSEG is not currently subject to any rate assessments for failure to meet the targets (SM 146).

NYSEG and RG&E argue, however, that modeling the rate assessments for the future on the requirements of the KeySpan/Grid Order is improper. They maintain that they have an excellent record of satisfying their targets, and so imposing higher assessments on them as a result of the Iberdrola acquisition is unreasonable (SM 146-47).

An electric reliability performance mechanism is a common feature of electric utility rate plans, and should be required of any such plan adopted here. Since the characteristics of Iberdrola's proposed acquisition strongly resemble the circumstances at issue in the KeySpan/Grid Order, that Order is precedent on the level of rate assessments that are needed.

B. RG&E's Commodity Service Option

The conditions governing NYSEG's FPO offering was substantially revised in 2007, in the NYSEG Commodity Order.[23] There, the mark-up NYSEG earned on the FPO offering was substantially reduced, because the Commission found it excessive, and the earnings sharing mechanism for revenues attributable to the FPO was substantially reconfigured. In comparison to NYSEG, RG&E now over earns substantially on its commodity offering.

In any new rate plan adopted here, the requirements of the NYSEG Commodity Order should be applied to RG&E's FPO offering (SM 1669-73). The mark-up RG&E can earn should be reduced to the level NYSEG currently earns. The earnings sharing mechanism should be modified to conform to the NYSEG conditions, with 85% of the over-earnings accruing to ratepayers and 15% accruing to shareholders, above a threshold level of $4.5 million of pre-tax earnings that shareholders may retain.

[23] Case 07-E-0479, New York State Electric & Gas Corporation, Order Establishing Commodity Program (issued August 29, 2007).

The threshold is comparable, for RG&E's size, to the level of earnings NYSEG was allowed to retain.

The petitioners claim that RG&E's existing FPO mechanism should continue in effect. The only reason they offer justifying retention, however, is the inclusion of the existing provisions in the existing rate plan (SM 379). Once that rate plan expires, on December 31, 2008, there is no reason to continue its provisions and the more-recent guidance from the NYSEG Commodity Order should be substituted instead.

C. The Revenue Adjustments

A number of revenue adjustment issues were fully litigated on the record in this proceeding. They should be decided so that parties are not compelled to re-litigate these issues again, and so that a rate proceeding following approval of the transaction, if it is granted, may proceed expeditiously. In particular, compliance issues from the prior proceedings should be decided promptly. In some cases, these issues have been festering for years and resolution is needed now.

1). NYSEG ACF Issues

a. NYSEG Over-Earnings

A regulatory adjustment is required to correct errors in the ACF calculations NYSEG has submitted. In some cases, the company understated monies owed to ratepayers, and in other cases they have overstated monies ratepayers owed them.

In making compliance filings for earnings sharing under its prior electric plan, NYSEG repeatedly performed its calculations using an excessive amount of rate base and an excessive level of equity. It also overstated other deferrals. A proper calculation of earnings sharing, and deferral issues, would increase the amount owed ratepayers by $66.4 million through June 2008, including interest. This amount reflects Staff’s revised computation on standby rate deferrals (see SM 1753-55, Exh. 128, which reflects a total amount of $66.8 million).

Instead of disagreeing with the substance of the regulatory adjustments Staff made to correct errors in Annual Compliance Filings (ACF) calculations (SIB 181-90), the petitioners protest that Staff delayed informing them of the errors (SM 360). There is no merit to this baseless accusation, which, conveniently, distracts attention from the fault in the companies’ calculations.

The fault for the delays lies with NYSEG and RG&E. They have failed to timely provide necessary information and have repeatedly revised the ACF initial filings, sometimes years later, making adjustments amounting to millions of dollars (SM 1654-55). The scope and breadth of the revisions the companies make are detailed at Exhibit 19 (Response IBER-0342), where over one hundred changes to ACF filings are listed. Since it is the companies’ belated submittals and continual updating of filings that prevent Staff from completing its ACF audits (SM 1754-55), the companies should not be heard to blame Staff for the delays that have resulted.

Moreover, Staff has informed NYSEG of the most significant error it makes in calculating over-earnings. Indeed, it provided that assessment in 2003, soon after the very first NYSEG compliance filing on over-earnings was received. As detailed at Exhibit 38, Staff explained to the company that it was overstating the amount of common equity it used to calculate over-earnings, by using an amount that exceeds the actual level of common equity. Instead, the correct procedure is to use the actual amount of common equity, so long as it is no more than 45%. NYSEG artificially boosted its level of common equity so that it exceeded that actual common equity balance in making its compliance filings even though its actual equity ratio was less.

NYSEG nowhere disputes the accuracy of Staff’s criticism of its over-earnings calculation. Moreover, it has ignored Staff’s recommendation on the calculation even though Staff presented that recommendation in June 2003. NYSEG should be required to correct its over-earnings calculation errors, and direct to ratepayers the share of over-earnings they are owed, in Staff’s rate plan process.

b. The NYSEG Standby Deferral

Another adjustment to NYSEG's ACF is needed to reflect an error in its calculation of a deferral for standby rate expense. While NYSEG, when standby rates were first introduced, was permitted to recover the difference between those rates and the higher otherwise-applicable tariff rates, it has substantially overstated those lost revenues.[24]

NYSEG commenced calculating the lost revenues attributable to Cornell University (Cornell), its largest standby customer, by comparing the revenues received at standby rates to the revenues received under Cornell's rate classification prior to the time it switched to standby rates. That pre-existing classification was S.C. 7 Transmission - High Load Factor (HLF). But for the period from April 2004 through December 2006, NYSEG changed the calculation. Instead of comparing the Cornell standby revenues to the HLF revenues, it compared them to S.C. 7 Non-HLF revenues. Since the non-HLF rates are considerably higher than the HLF rates, NYSEG was able to substantially increase the amount of lost revenues it claimed (SM 1625-28).

NYSEG justifies its excessive deferral by arguing that, while Cornell met the 68% load factor test for obtaining

[24] Case 02-E-0779, New York State Electric & Gas Corporation, Order Establishing Electric Standby Rates (issued July 30, 2003)(NYSEG Standby Order).

the HLF rate at the time it switched to standby service, beginning in April 2004, it could no longer meet that test. As NYSEG concedes, however, Cornell met the 68% load factor test at the time it became a standby customer. The purpose of the lost revenue calculation was to enable NYSEG to recover the difference between the revenues received under the new standby rates and the revenues it would have received from the customer had standby rates not been introduced. Since Cornell met the 68% load factor test at the time it switched to standby rates, it is clear that the revenues NYSEG actually lost are those in comparison to the HLF rates. Had there been no standby rate, Cornell could have continued to meet the 68% load factor test and could continue to have qualified for the HLF rate.

Indeed, had any rate forecast for NYSEG been made at the time, the assumption would have been to forecast Cornell as an HLF customer. It is that assumption that drives the lost revenue recovery, not events subsequent to the time that Cornell left the HLF rate for standby service, like the loss of qualification for a no-longer relevant S.C. 7 HLF rate.

Moreover, maintaining the 68% load factor was the prerequisite for obtaining the lower HLF rate. In other words, there was a strong incentive for an S.C. 7 customer to qualify for the much lower HLF rate (instead of the default, and higher non-HLF rate), and to keep its load factor at 68% or above in order to do so. Once Cornell switched to standby service, however, there was no longer an incentive to maintain the 68% load factor, because once, on standby service, its rates would remain the same whatever its load factor. Since the 68% load factor test was relevant so long as the customer remained on the S.C. 7 rate, and was not relevant when it moved to the standby rate, it is also irrelevant for the purposes of determining lost revenues (SM 190-97).

NYSEG contends that using non-HLF rates for the lost revenue calculation was appropriate, because it determined that, as of April 2004, Cornell could no longer meet the 68% load factor test. Since that fact is irrelevant, NYSEG's entire argument collapses. It also fails to address the fact that, under the NYSEG Standby Order, lost revenue recovery was intended to make it whole for the difference between revenues received at standby rates and revenues that would have been received otherwise. Clearly, the revenues it would have received otherwise for Cornell were the HLF rates, which should serve as the basis for the deferral used in Staff's rate plan process.[25]

[25] Staff agrees to a correction NYSEG made, at SM 185-86, to Staff's calculation of the difference between standby rates and HLF rates.

2). RG&E ACF Issues

Several of RG&E's ACF filings raise rate issues. Staff's proposed corrections should be recognized in its rate plan process.

a. Storm Costs

Under its Rate Plan Order, RG&E is permitted to recover storm costs that exceed a $250,000 threshold. As its Rate Plan provides, however, storm restoration efforts costing less than $250,000 will not be recovered and instead "will be charged to RG&E's operating expense."[26] As a result of that provision, storm cost recovery is limited to operating expenses only.

In its ACF filings, RG&E has in at least one instance sought to recover, in addition to operating expenses, capital expenses it attributed to storm damage. Capital costs, however, may not be included in the calculation. Capital costs are recovered through rate base and depreciation, and so are borne by ratepayers irrespective of whether caused by a storm or not. By including capital costs in the storm cost threshold, the company is double counting and therefore its position is incorrect.

Moreover, like any other utility deferral, RG&E may recover only its incremental expenses in the storm damage

[26] RG&E Rate Plan Order, App., §XI.2.a.

deferral. The utility already recovered non-incremental expenses, such as labor and benefits for employees who work during a storm, in its rates. To recover those non-incremental expenses again through the storm damage deferral would be another double-count.

RG&E also claims that it suffered a “heat storm” event that qualifies for storm deferral. Hot weather, however, does not constitute a storm. Rather, it is an expected weather event, and the delivery system should be designed to function when temperatures rise. That is, hot and humid weather are a common summer occurrence within the systems design parameters. RG&E has not demonstrated that heat falls within the definition of a storm event, and so it should not be permitted to recover costs related to such an alleged event (SM 387).

b. The Security Cost Deferral

Staff also objects to RGE’s improper security cost deferral. Again, such deferrals are limited to incremental costs. RG&E seeks to include all costs, thereby double-counting costs it already recovers in rates (SM 166, 391).

c. The VYC Deferral

Under its Rate Plan Order, RG&E was authorized to defer outreach and education (O&E) expenditures for informing customers of its Voice Your Choice (VYC) retail access program, but only if it could show that it was required to expend more than $2 million for that purpose. Through the fourth year of its five year rate plan, RG&E incurred $8.3 million and deferred $6.3 million for recovery from its rate payers. Staff believes the level of expenditures RG&E incurred was excessive (SM 1665-66), because the $2 million spending allowance should have been adequate. Moreover, RG&E has not shown it was required to spend the additional amounts, as is necessary to justify the deferral.

RG&E protests that it was not notified that "Staff was not satisfied with the level of its VYC O&E efforts." The company also claims Staff "review[ed] and discuss[ed]" VYC O&E with it (SM 345-47). That Staff might have "reviewed" the content of RG&E's O&E efforts and determined that it was accurate and informative, however, does not demonstrate it reviewed or accepted the costs RG&E incurred, or that RG&E could not have produced the same materials at lower costs.

A comparison of expenses NYSEG incurred for O&E related to its similar retail access program is instructive. Over the four-year period when RG&E was spending $8.3 million for retail access O&E, NYSEG spent about $2.5 million (SM 439), even though NYSEG has approximately 750,000 customers while RG&E has only 320,000 customers (Exh. 19, Response IBER-340). In other words, for the four-year period, RG&E was spending approximately $6.49 per customer for retail access O&E expenses, while NYSEG was spending $.84. It should be noted that NYSEG was not permitted to recover such O&E expenses through a deferral. RG&E’s expenditures are therefore excessive, and the deferred $6.3 million should not be recovered from ratepayers.

Rather than justifying its expenditures with a detailed analysis of the amount it spent, RG&E, like NYSEG in addressing their over-earnings deferral, seeks to blame Staff for the excessive deferral it has accumulated (SM 346, 437-38). Again, like NYSEG, RG&E did not provide for any process in its rate plan for reviewing deferrals as they accumulated. Contrary to the Petitioner’s claims, Staff did question the amount of the deferral (SM 1714-1715),[27] and RG&E could have pursued the matter further had it desired. It did not do so.

Therefore, RG&E has failed to show that the $6.3 million it seeks to recover over the $2.0 million it was allowed for O&E efforts is warranted. Recovery of that amount should be denied.

3). Software Costs

In any new rate plan for NYSEG and RG&E, depreciation and related rate base for capitalized software should be eliminated. The effect of capitalizing software costs, where a utility was allowed to recover the same software expense in

[27] The petitioners may claim the question was presented to NYSEG, not RG&E, but the interchangeability of NYSEG and RG&E personnel during the course of this proceeding demonstrates each is well aware of events affecting the other.

rates already, causes ratepayers to pay twice -- once as a rate year expense and then again over time for depreciation and a return on un-depreciated costs.

NYSEG has insisted upon recognizing in rate base capitalized computer software costs even though it has recovered software expenses in rates. It never received permission for this accounting treatment, notwithstanding that it sought that permission (Exh. 39).

In disputing Staff’s analysis of the NYSEG software expense, the petitioners claim that the NYSEG Electric Rate Order resolved the issue in NYSEG’s favor. The petitioners interpret that Order as making a distinction between the types of software that were treated as a benefit of the prior merger when Energy East was formed, which should be written off, and the investment in the more recent Customer Care System (CCS), which, they allege, the Commission decided should not be written off.

The petitioners assert their interpretation of the NYSEG Electric Order also applies to the capitalization of software at RG&E. It therefore rejects Staff’s adjustment to CCS costs included in rate base at that utility as well (SM 374-76). The petitioners add an argument that Staff’s calculation of its CCS adjustment is overstated as well (SM 377-78).

Notwithstanding the companies’ arguments, software expenses are not treated as capital expenditures under the Commission’s Uniform System of Accounts. Before they can be capitalized, permission must be obtained.

Nor is the petitioners’ criticism of Staff’s CCS adjustment calculation warranted. The criticism is based on a claim that a portion of the CCS balance was not being depreciated at a time when the depreciation was reflected in Staff’s calculation. Although the company correctly points out that the CCS cost was not being depreciated at that time in common plant accounts, it was, as the company admits, being depreciated in another account elsewhere (SM 431). As a result, Staff’s calculation is correct, because the total depreciation cost remains the same even though the amount was being depreciated in one account at one time and then was transferred to another account subsequently.

Nor, as the petitioners contend, was this issue fully resolved in the NYSEG Electric Order. While NYSEG there was allowed to replace CCS costs in rate base, the accounting there amounted to deferral accounting and applied only to NYSEG electric rates, and was also contingent upon future review and adjustment. The specific concern noted by the Commission in that Order was that the CCS system might be shared with Energy East affiliates. The Commission did not specifically rule that a change of accounting to allow for capitalization of software cost had been or would be approved. After the Commission Order, NYSEG again sought permission to capitalize software and the Director of Accounting & Finance declined (Exh. 39).

As a result, permission to perform the capitalization for NYSEG gas and RG&E electric and gas was still required, but was not obtained. Moreover, the NYSEG electric amounts remain contingent upon future events. Besides sharing among affiliates to reduce the costs, it is also possible that the CCS cost system itself might become obsolete. In addition, Exhibit 122 shows that NYSEG included software cost in rates as an expense and therefore, the capitalized costs should be removed from future rates, in Staff's rate plan process.

4). Gas Pension Expense for NYSEG

Under the NYSEG Gas Rate Plan Order, the company is permitted a limited true-up of pension expense (SM 369-70). Staff proposes to eliminate this true-up in the future (SM 1751). The true-up that is performed uses outdated financial metrics and is not consistent with the approach to pension deferrals taken in the Commission's Policy Statement on Pensions and OPEB.[28] The NYSEG Electric Order used the latest available

[28] Case 91-M-0890, Accounting for Pensions, Statement of Policy and Order Concerning the Accounting and Ratemaking Treatment for Pensions and Post Retirement Benefits Other Than Pensions (issued September 7, 1993).

pension expense forecast and a similar deferral for electric service was not provided. Therefore, once NYSEG's gas rate plan expires, the partial true-up provision should disappear with it, and the gas rates adopted in Staff's rate plan process should reflect future pension expenses consistent with latest available information with no true up.

D. ROE

The petitioners complain that Staff calculated a return on equity (ROE) for NYSEG and RG&E at 9.0%, when 9.8% was granted in the KeySpan/Grid Order (PIB 89, 95). The 9.8% ROE in that proceeding, however, was tied to a five-year rate plan. The longer the rate plan, the higher the ROE, because the greater the risk a utility faces over the longer term. The KeySpan/Grid Order confirms this axiom, by noting that a three-year rate plan would justify only a 9.6% ROE, instead of the 9.8% ROE a five-year plan would warrant.[29]

Since Staff calculated its 9.0% ROE for a one-year period, in conformance with Commission approved methods (SM 1389-1400), its calculation is unaffected by the analysis in the KeySpan/Grid Order applicable to three-year and five-year rate plans. And Staff's 9.0% figure aligns with recent Commission

[29] KeySpan/Grid Order, p. 78.

decisions adopting one-year ROEs of 9.1%.[30] Therefore, Staff's ROE is reasonable, but should be updated in the rate plan process. In addition, if a multi-year rate plan is developed, it should provide for a revenue sharing mechanism for earnings in excess of the allowed return.

E. Gas Cost Incentive Mechanism

Under the currently-effective NYSEG and RG&E Gas Rate Plans, certain costs are shared between ratepayers and shareholders through two Gas Cost Incentive Mechanisms (GCIM-1 and GCIM-2). Consistent with policies applicable to all New York LDCs,[31] GCIM-1 (Utility Stand-Alone Activities) establishes an incentive for NYSEG and RG&E to maximize revenues from existing capacity and supply contrasts and to mitigate impacts of excess system capacity during off peak periods or when not utilized by firm core customers. Unlike GCIM-1, GCIM-2 (Energy East's Multi-State LDC Activities) is specific to Energy East, and provides for a sharing of savings attained through specific joint Energy East affiliate optimization of gas supply

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[30] Case 07-G-0141, National Fuel Gas Distribution Corporation, Order Establishing Rates For Gas Service (issued December 21, 2007)(NFG Order), p. 41; Case 07-E-0513, Consolidated Edison Company of New York, Inc., Order Establishing Rates For Electric Service (issued March 15, 2008)(Con Ed Electric Order), p. 126.

[31] See Case 93-G-0932, Restructuring Natural Gas Markets, Opinion No. 94-26 (issued December 20, 1994).

portfolios, including gas storage, transportation and pipeline capacity turn-back activities (SM 1847-48).

GCIM-2, however, unnecessarily over-compensates the two LDCs. They are already required to procure and manage gas supply for their customers on a least cost basis, pursuant to PSL §§66(e) and (f). Moreover, the Commission’s regulations, at 16 NYCRR §61.3.6, guide their gas purchasing policies and load management practices. Rewarding the two LDCs for performing their duties with the prudence expected of utility management is no longer appropriate.

NYSEG and RG&E argue that GCIM-2 should be continued. They believe that the joint optimization practices between the two of them have yielded savings, and they point to the Commission’s Orders and other documents where GCIM-2 methodologies were approved or established (SM 384-85).

That GCIM-2 was a feature of the joint proposals adopted by the Commission when establishing existing rate plans does not demonstrate that its continuation is appropriate when those rate plans expire as of December 31, 2008. Those joint proposals, like any settlement, are not precedent for continuation of any of their terms or conditions.

Moreover, the LDCs are expected to prudently manage their gas transportation storage and pipeline capacity activities for the maximum benefit of their ratepayers. It is not appropriate to reward the companies for the performance of the duties expected of them. Utility managements are expected to make that type of decision prudently, and are compensated accordingly.[32] The reward for merely prudent operation inherent in GCIM-2 is no longer appropriate, and the mechanism should be eliminated in Staff's rate plan process.

F. Implementation of Commission Policies

1). Revenue Decoupling Mechanisms

In a Notice Consolidating Proceedings issued October 22, 2007 in this proceeding, it was decided that issues related to the development and implementation of a revenue decoupling mechanism (RDM) for electric and gas sales by NYSEG should be considered in this proceeding. Those issues thereby would become a component of any rate plan devised as a result of this proceeding. While only NYSEG was directed to develop an RDM, it is similarly appropriate to develop such a mechanism for RG&E at this time. In both cases, implementation of an RDM would comply with the Commission's RDM Order.[33] It should be emphasized,

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[32] Case 90-E-0775, Consolidated Edison Company of New York, Inc., Order Accepting Contracts for Filing and Denying Petition (issued December 10, 1990); Case 92-E-0032, Erie Energy Associates, Declaratory Ruling (issued March 4, 1992).

[33] Case 03-E-0640, Electric Delivery Rate Disincentives, Order Requiring Proposals for Revenue Decoupling Mechanisms (issued April 20, 2007).

however, that accurate sales forecast data is a critical prerequisite to establishing RDMs (SM 1629, 1850).

As a result, Staff proposed RDMs for both electric and gas sales (SM 1629, 1849-51). Although protesting that adoption of an RDM should not be a condition of approval of this transaction, NYSEG and RG&E responded by committing to filing RDM proposals. While agreeing that accurate weather-normalized sales forecast data is needed to establish an RDM, the companies also criticized some aspects of Staff's RDM proposals (SM 264-70).

These issues should be addressed in the rate plan process Staff recommends. Guidance may be obtained from the Commission's recent decisions on an RDM mechanism for Con Edison.[34]

2). Capital Expenditures (CAPEX)

Staff proposes electric and gas capital expenditure (CAPEX) accountability mechanisms for both NYSEG and RG&E. These mechanisms ensure that the companies expend the amounts they say are needed to maintain system integrity, reliability and safety, and support customer growth (SM 1617, 1844). CAPEX

[34] Case 06-G-1532, Consolidated Edison Company of New York, Inc., Order Adopting in Part the Terms and Conditions of the Parties' Joint Proposal (issued September 25, 2007)(Con Ed Gas Order); Con Edison Electric Order.

accountability mechanisms have been a feature of prior rate plans for both NYSEG and RG&E.

Moreover, to assist in planning capital expenditures that best bolster electric system reliability, NYSEG and RG&E should be required to file annually a five-year forecast of planned electric system upgrades. The filing should forecast expected costs for each project or program and reconcile the prior year's construction with previous forecasts. To address concerns about aging infrastructure, the utilities also should prepare and file an assessment of the physical condition of their electric systems, including remedial actions for remedying deficiencies that are discovered and a monitoring program for identifying deficiencies that arise in the future (SM 1861).

a. <u>NYSEG Electric CAPEX</u>

While a CAPEX mechanism is not in effect for NYSEG electric at this time, because one was not imposed in the 2006 NYSEG Electric Order, such a mechanism was in place for electric expenditures during the rate plan in effect from 2002 through 2006. That plan provided that, if NYSEG's actual capital expenditures were $40 million less than the $355 million target at the end of the rate plan, a ratepayer credit would have been set at 25% of any excess over the $40 million shortfall (SM 1618-19).

For calendar years 2009 and 2010, NYSEG is currently forecasting total electric capital expenditures of approximately $285 million, not including expenditures on advanced metering infrastructure. This forecast exceeds actual expenditures for the prior two years by approximately $100 million, primarily due to a proposal to reinforce transmission into the Ithaca area.

If this transaction is approved, a new CAPEX mechanism should be adopted for NYSEG through Staff's rate plan process (SM 1617-19). If its actual capital expenditures fall short of the forecasted target, it should be required to defer the carrying costs on the budgeted shortfall for the future benefit of customers. The revenue requirement impact would be calculated by applying the company's annual carrying charge to the annual shortfall from the average annual budget forecast amount. In addition, NYSEG should be required to submit to Staff its management-approved annual electric budget, detailed by project, for each of the next three years, and an annual filing detailing actual expenditures and any variances from forecast.

b. RG&E Electric CAPEX

RG&E's current electric rate plan provides for a CAPEX accountability mechanism. Over the five-year term of the rate plan, from 2004 through 2008, expenditures were forecast at $280 million. If total actual expenditures at the end of the rate plan fall short of the target by more than $25 million, ratepayers will receive a credit of 25% of any excess over the $25 million shortfall. If actual expenditures exceed the target by more than $25 million, ratepayers will be charged 11% of any excess over the $25 million amount that has not accrued allowances for funds used during construction (SM 1621-22).

Currently, RG&E's capital expenditures substantially exceed the $280 million target, because the company has exceeded forecast costs for the Rochester Transmission Project (RTP) by approximately 60%. Moreover, the company has alleged that it may need to construct additional transmission into the Rochester area, notwithstanding the RTP upgrades. In addition, the company may have improperly included software costs in its capital expenditures (SM 1622-23).

If this transaction is approved, a new CAPEX mechanism should be adopted for RG&E through Staff's rate plan process. If actual 2009 and 2010 expenditures fall short of Staff's adjusted forecast of $182 million, RG&E should defer a credit equivalent to the carrying costs on the budget shortfalls, for future benefit of customers, similar to the mechanism proposed for NYSEG. Filing requirements similar to those proposed for NYSEG should be imposed on RG&E (SM 1623).

The mechanism, however, should not provide for payment of an incentive to RG&E if capital expenditures are exceeded.

Such an incentive does not necessarily inspire the company to improve service to ratepayers, but instead rewards it for any spending in excess of the target, even if the spending is excessive or imprudent. It also improperly rewards efforts to under-forecast the targets. Such an incentive is also unneeded, because, where appropriate, the company can accrue AFUDC carrying charges before a project enters service and is still under construction (SM 1624).

c. NYSEG and RG&E Gas CAPEX

CAPEX mechanisms are also needed for gas construction budgets at NYSEG and RG&E. For the next three years, NYSEG has forecasted its capital expenditures at $20.8 million per year, while NYSEG is projecting $19.3 million per year (SM 1845-46). Those forecasts seem reasonable, based on recent actual historic experience (SM 1846).

Staff proposes CAPEX mechanisms for NYSEG and RG&E gas that are similar to those proposed for NYSEG and RG&E electric. Specifically, if the actual annual amount expended by either company is less than the annual average amount budgeted for the three-year period from 2008 through 2010, the company would be required to defer the carrying costs on the budgeted shortfall for the future benefit of customers. In addition, the company should be required to provide Staff with their management-approved annual gas budgets, detailed by project, for each of the next three years. Each company should also be required to make a filing detailing their annual expenditures, and explain any variances from forecast, within two months after the end of each calendar year (SM 1847).

NYSEG and RG&E propose that the CAPEX mechanisms include an incentive. They maintain that any amount they overspend above their capital budgets should be subject to a carrying charge accruing to the benefit of shareholders (SM 385-86). To establish spending levels and the reconciliation methodology, the companies would conduct collaborative meetings.

As with electric CAPEX mechanisms, gas CAPEX accountability mechanisms are necessary to ensure that NYSEG and RG&E perform budgeted capital improvement work that is necessary to maintain system reliability and safety. Moreover, if forecasted capital expenditures are reflected in rates, but the company does not expend those amounts, it retains that benefit for shareholders. In an era when infrastructure needs call for more attention, not less, this outcome is unacceptable.

As with the electric CAPEX mechanism, the companies should not be rewarded if they exceed forecast expenditures. Again, this type of incentive rewards the company even if their spending is excessive or even imprudent. Utilities should not earn incentives in such instances. Therefore, the Commission should direct that Staff's CAPEX accountability mechanisms be implemented in Staff's rate plan process.

3). Retail Access Issues

The Staff Policy Panel addressed several retail access unbundling issues, including unresolved billing issues related to NYSEG and RG&E. These utilities currently apply their billing charges in a manner that does not conform to Commission policy and orders. The Staff Policy Panel also testified that the unbundling of rates from back-out credits to unbundled charges for service should be completed. As well, the Panel addressed the establishment of an ESCO Referral Program for both NYSEG and RG&E (SM 1437).

a. Bill Issuance and Payment Processing

The Commission has addressed bill issuance and payment processing (BIPP) twice on a generic basis.[35] In both cases, the Commission ruled that the customer should only pay a utility for BIPP service when receiving from the utility both delivery and all commodity services (SM 1438-1439). When the customer receives a consolidated bill, which includes ESCO as well as utility charges, from the utility, the utility collects a billing fee equal to the amount of the BIPP charge from the ESCO

[35] Cases 98-M-1343 and 99-M-0631, Customer Billing Arrangements, Order Providing For Customer Choice of Billing Entity (issued May 18, 2001); Case 00-M-0504, Competitive Opportunities, Order Directing Submission of Unbundled Bill Formats (issued February 18, 2005)(Bill Format Order).

or ESCOs. Where a single ESCO serves the customer for either both commodities or one of two commodities taken, it still is required by the Commission to pay the entire BIPP fee. Where there are two ESCOs serving the customer, one for electricity and one for natural gas, the ESCOs would each pay half of the BIPP fee. As a result, where an ESCO is providing all or one part of a dual commodity service, the companies should not charge the customer for billing services because the ESCO is already paying them (SM 1439).

When the NYSEG and RG&E retail access rate design was accomplished through back-out credits, those credits were set in conformance with the Commission's Orders on BIPP. But when the utilities converted the back-out credits to charges, they began using two separate BIPP charges, one for electric service and one for gas service, imposing on dual commodity customers a total BIPP charge approximately double the amount a single commodity service customer pays. The Commission, however, has determined that the BIPP charge should be one charge that is the same whether the customer is a single commodity service customer or a dual electric and gas commodity service customer (SM 1440).

Besides departing from the requirements of Commission orders and policy, the approach NYSEG and RG&E take to BIPP is inconsistent with the BIPP charge practices of the other New York utilities. The approach also does not reflect the actual costs NYSEG and RG&E incur in providing BIPP. A large part of BIPP costs are related to the costs of the supplies needed to prepare bills, such as ink, paper, and envelopes; the machines that print, assemble, and put the bills in envelopes; and the postage. These costs are calculated per bill, and do not vary whether one commodity is taken from a utility competitor or both electric and gas commodity are so purchased (SM 1440-1442).

The Commission has repeatedly recognized and stated that BIPP costs should be paid by the customer only when the customer takes both commodities from the utility. When one or more commodities are purchased from competitive suppliers, however, the ESCO pays the charge (SM 1443). For example, the Commission stated: “[s]ince the billing charge is for a competitive service and is not charged to retail access customers receiving consolidated bills, from either the utility or the ESCO, it should not be subsumed within delivery.”[36] Therefore, billing is a single competitive service paid by customers only when they receive no commodity service from a competitive supplier or ESCO.

More recently, the Commission distinguished “the gas Merchant Function Charge” from “the account level billing and payment processing charge.”[37] This further clarified that there

[36] Bill Format Order, p. 23.

[37] Con Ed Gas Order, p. 9.

should be a single BIPP charge, not two separate charges for electric and gas (SM 1443-1444). The Commission should insist that NYSEG and RG&E comply with established BIPP policy in Staff's rate plan process. So considering BIPP in a rate plan context should resolve the companies' concerns about addressing this issue outside of a rate proceeding (SM 173).

b. Further Unbundling of Utility Rates

The unbundling process for the Energy East utilities is not yet complete. While many of these utilities' charges have been unbundled from rates and are no longer subject to back-out credits, RG&E in particular should be required to file revised tariffs that convert all existing back-out credits to unbundled charges in a revenue neutral manner, including the merchant function credit and metering back-out credits (SM 1444).

c. ESCO Referral Programs

Neither NYSEG nor RG&E currently operate an ESCO Referral Program, where an electric or gas utility offers customers telephoning its call center with a non-emergency inquiry the opportunity to enroll with ESCOs that offer a uniform discount, over an introductory trial period, from the price the utility charges for commodity service (SM 1444-1445). Recently, the Commission ordered KeySpan and NFG, two New York utilities currently without ESCO Referral Programs, to initiate collaboratives to investigate the possibility of initiating such programs.[38] In each case, the Commission required each utility to embark upon a collaborative and to make a filing describing the relevant costs, benefits and best practices of an ESCO Referral Program, in sufficient detail to allow the Commission to reach a decision on such a program (SM 1445).

NYSEG and RG&E have, respectively, filed proposals, on September 1, 2006 and October 23, 2006, to institute ESCO Referral Programs, upon which the Commission has not yet acted. Subsequently, in the NYSEG Commodity Order, the Commission allowed NYSEG to pursue the development of an ESCO Introduction Program that could serve as a substitute for an ESCO Referral Program (SM 1445-1446).

Since the original ESCO Referral Program filings of RG&E and NYSEG are nearly two years old, the Commission should impose on NYSEG and RG&E requirements regarding ESCO Referral Programs that are similar to the requirements the Commission imposed on KeySpan and NFG (SM 1447), for implementation in Staff’s rate plan process. NYSEG should be required to submit in that process cost and program component information on an ESCO Introduction Program, and compare that program to the costs

[38] Case 06-G-1185, KeySpan Corporation, Order Adopting Gas Rate Plans For KeySpan Energy Delivery New York and KeySpan Energy Delivery Long Island (issued December 21, 2007); NFG Order.

and best practices for implementing an ESCO Referral Program (SM 1447).

4). AMI

NYSEG and RG&E have proposed to install advanced meter infrastructure (AMI) in their service territories, and recover the costs of AMI in a surcharge to customers (SM 1743-51). Because AMI is an extensive meter replacement program that raises numerous and complex issues, it requires additional review. The accuracy of the companies' estimates of costs and savings and their surcharge calculations are questionable. Moreover, the program must be coordinated with the Commission's evolving standards on AMI.[39]

Particularly troubling to Staff is the companies' failure to address the fact that, if AMI meters are installed, the existing meters would be retired. Upon retirement, depreciation of the meters should cease, but, under the companies' approach, they would continue to recover the depreciation expenses reflected in their existing revenue requirements (SM 1743-50). A claim that the public policy benefits attending installation of AMI justify continued depreciation recovery is not sufficient to show that recovery is

[39] See, e.g., Case 02-M-0514, Competitive Metering, Order Requiring Filing of Supplemental Plan (issued December 19, 2007).

actually warranted (SM 407-08). Only a more detailed cost analysis can make that demonstration.

A careful approach to the AMI issue is needed. Therefore, AMI issues should be excluded from Staff's rate plan process. Consideration of those issues should be postponed until additional proceedings on AMI have been conducted; proposals to install AMI in the NYSEG and RG&E service territories have been carefully analyzed; and, all of the questions Staff has raised here have been answered. Such further proceedings should be conducted as the Commission directs in its ongoing development of AMI policy.

5). Low Income Programs

NYSEG and RG&E currently administer several ratepayer-funded low-income programs, including NYSEG's Power Partner Program for electric customers, its Affordable Energy Program for gas customers, and RG&E's Residential Energy Customer Assistance Program (RECAP) and Non-Heating Gas Low-Income Program for gas customers. RG&E, however, does not currently conduct a low-income program for its electric customers (SM 1886-90). Staff proposes continuation of the existing programs, at increased funding levels, and establishing a low-income electric program for RG&E modeled on NYSEG's Power Partner Program. While willing to continue their existing programs, NYSEG and RG&E oppose increasing their funding, and oppose establishing an electric low-income program at RG&E without providing for its funding in rates (SM 135-37).

Low-income programs are now a common feature of all electric and gas utility rate plans. Staff's proposed levels of funding are generally commensurate with those at other utilities. There is no reason to exempt NYSEG and RG&E from this generally applicable requirement. Moreover, NYSEG has successfully operated separate electric and gas low-income programs for many years. RG&E should be able to do the same. As with all other rate issues related to this proceeding, the costs of these programs should be addressed in the Staff rate plan process.

6). Economic Development Programs

Like Low Income programs, economic development programs remain an essential element of any electric or gas utility rate plan. For example, RG&E was recently required to update its proposed rate discount and non-rate economic development program spending for 2009, while identifying the sources of the funding for its proposals.[40] Therefore, NYSEG and RG&E should be directed to address their economic development programs and economic development spending in the rate plan process Staff proposes.

[40] Case 02-E-0198, Rochester Gas and Electric Corporation, Order Modifying Economic Development Program Portfolio and Raising Non-Rate Program Spending Ceiling (issued April 25, 2007).

7). <u>O&E Plan Filings</u>

Staff proposes to continue existing O&E plan filing requirements for NYSEG and RG&E's customer information efforts, bolstered by more detailed budget reporting (SM 1890-91). NYSEG and RG&E oppose additional reporting. As regulated utilities, however, they are required to provide the information necessary for Staff to perform its oversight function (SM 138). Implementation of Staff's O&E requirements should take place in Staff's rate plan process.

CONCLUSION

For all the above reasons, Staff's exceptions to the Recommended Decision should be granted, and if denied, Staff's alternative should be adopted instead.

Respectfully submitted,

Leonard Van Ryn
Sean Mullany
Staff Counsel

Dated: June 26, 2008
Albany, New York

Case No. 07-M-0906

Iberdrola, S.A. and Energy East Corp.

Staff Response to Request For Information

STAFF RESPONSE TO: IBER/EE IR No. DPS 83

PREPARED BY: Electric Reliability and Safety Panel

DATE: January 25, 2008

Question:

Reference page 238 of the Policy Panel Prepared Testimony:

Please explain how the analysis in Exhibit___(PP-21) would change if benefits over a 10-year period were analyzed?

Response:

Attached is Staff's analysis of merger benefits for a 10 year period in the format of Exhibit___(PP-21). Note this is based on corrected (lower) PBA amounts for RG&E and the revised (lower) RGS/Energy East merger savings. As shown, the savings percentages decline for each of the major mergers analyzed. The savings percentage for Iberdrola/Energy East decreases because the PBA adjustments are one-time adjustments while the rate benefits in the other cases in part represented on-going savings.

RESPONSE TO I/E (DPS) 083

Iberdrola/Energy East
Positive Benefits Adjustments Comparison

10 Year Impact
$ Millions
Response to I/E (DPS)-083

Iberdrola/Energy East	RG&E	NYSEG	Total	
delivery revenues	$ 1,035.4	$ 1,566.4	$ 2,601.8	
cumulative revenues	$ 5,177.0	$ 7,832.0	$ 13,009.0	
cumulative reductions	$ (386.5)	$ (346.4)	$ (732.9)	
% of delivery	-7.5%	-4.4%	-5.6%	

KeySpan/Grid	KEDNY	KEDLI	Total	
delivery revenues	$ 1,362.8	$ 979.2	$ 2,342.0	
cumulative revenues	$ 6,814.0	$ 4,896.0	$ 11,710.0	
cumulative reductions	$ (333.7)	$ (359.1)	$ (692.9)	(a)
% of delivery	-4.9%	-7.3%	-5.9%	

Energy East/RGS	RG&E	NYSEG	Total	
delivery revenues	$ 1,035.4	$ 1,566.4	$ 2,601.8	
cumulative revenues	$ 5,177.0	$ 7,832.0	$ 13,009.0	
cumulative reductions	$ (294.3)	$ (363.0)	$ (657.2)	(b)
% of delivery	-5.7%	-4.6%	-5.1%	

(a) $90 million KEDLI/KEDNY benefits years 6-10 + $602.9 million
so: KeySpan/Grid Order pg. 119

(b) from Appendix A, years 1-5 assume net savings of $164.3 million
years 6-10 assume final gross savings of $76.7 million annually
plus 20% to reflect higher actual savings than projected.