VIA HAND DELIVERY

June 23, 2004

Honorable Jaclyn A. Brilling
Secretary
State of New York
Public Service Commission
Three Empire State Plaza, 19th Floor
Albany, New York 12223-1350

Re: Case 03-E-0188 - Proceeding on the Motion of the Commission Regarding a Retail Renewable Portfolio Standard

"Notice of Schedule for Filing Exceptions" (6/3/04)

JOINT UTILITIES BRIEF ON EXCEPTIONS

Dear Secretary Brilling:

Pursuant to the above-referenced Notice, enclosed please find for filing an original and twenty-five copies of the Brief on Exceptions submitted on behalf of Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation (collectively the "Joint Utilities").

Copies of these comments were served via e-mail today on the RPS Server-subscribed parties in this proceeding, including ALJ Stein. In addition, copies have been served via U.S. Mail on all Active Parties to this proceeding identified on the Commission's website.

Kindly acknowledge receipt of this filing by date-stamping as received the enclosed duplicate copy of this letter.

Respectfully submitted,

THE JOINT UTILITIES

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Enclosures

cc w/ encls: ALJ Eleanor Stein (via e-mail and U.S. Mail)
Active Parties (via e-mail and U.S. mail)

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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PROCEEDING ON THE MOTION OF THE	**:**	
COMMISSION REGARDING A RETAIL	**:**	**CASE NO. 03-E-0188**
RENEWABLE PORTFOLIO STANDARD	**:**	
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JOINT UTILITIES

BRIEF ON EXCEPTIONS

Dated: June 23, 2004

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JOINT UTILITIES

BRIEF ON EXCEPTIONS

INTRODUCTION

This Brief on Exceptions is submitted on behalf of Central Hudson Gas & Electric Corporation ("Central Hudson"), Consolidated Edison Company of New York, Inc. ("Con Edison"), New York State Electric & Gas Corporation ("NYSEG"), Orange & Rockland Utilities, Inc. ("O&R"), Niagara Mohawk Power Corporation ("Niagara Mohawk"), and Rochester Gas and Electric Corporation ("RG&E") (collectively the "Joint Utilities") in response to the Recommended Decision ("RD") and associated *Notice of Schedule for Filing Exceptions* issued June 3, 2004, by the Secretary to the State of New York Public Service Commission ("Commission") in this proceeding, and to the *Erratum Notice* issued June 16, 2004, by the Secretary. A summary of the complete procedural history of this proceeding is set forth in Attachment A, "Statement of the Case."

The Commission instituted this proceeding to develop and implement a Renewable Portfolio Standard ("RPS") for electric energy retailed in New York State. The Joint Utilities support the efficient use of energy and natural resources to enhance the economy and the environment in New York State. To these ends, the Joint Utilities have been active participants in these proceedings to design an RPS program.

To date, the record in this proceeding shows that RPS program costs will range upwards from $1.1 Billion depending on assumptions (particularly the level of RPS "targets," wholesale power prices, fuel costs and the time-periods that renewable resources will receive RPS premiums). The Joint Utilities believe that the RPS program recommended in the RD does not strike an appropriate balance among the important policy goals of controlling costs to consumers, and minimizing inconsistencies with retail and wholesale electricity markets in New York State and regionally, while also improving environmental quality, supporting fuel diversity and maintaining the paramount policy objective of system reliability.

SUMMARY

The RD is a mix of specific and general recommendations. It makes some very specific recommendations, such as: that the Commission ratify a 25% renewables goal, a timetable and annual renewables “targets,” specifications for eligibility, and that the Commission place compliance responsibility uniquely on certain Load Serving Entites ("LSEs") — investor-owned Transmission and Distribution ("T&D") utilities, Energy Services Companies ("ESCOs"), and the Long Island Power Authority ("LIPA") — and exclude "very small" ESCOs, the New York Power Authority ("NYPA") and municipal providers. The RD leaves significant issues unaddressed regarding implementation.

It is not unusual for development of Commission Policy to consider competing or conflicting objectives, but the present case is unusual in the number and significance of such objectives that are presented. For example:

- While the Commission has for many years called for utilities to develop supply portfolios under a “least cost” rubric, the “RPS premiums” by definition represent payments that exceed prices for power available in the wholesale markets.

- While the Commission has supported the New York Independent System Operator ("NYISO") and its Location Based Marginal Pricing ("LBMP") - based market model on grounds of producing lowest cost electricity reliably for consumers in the State, RPS premium payments to renewable generators will increase costs, may dilute price signals needed to provide incentives for new resource development; and operation of large quantities of intermittent renewables has reliability impacts not fully understood at this time.
- Production of power using renewable energy may not have the intended effect of significantly mitigating the use of fossil fuels and reducing air emissions, unless the RPS is properly integrated into wholesale energy markets. Since major types of renewable resources produce power during off-peak hours, increased operation of these types of renewables generation may cause other renewable resources to be turned off or dispatched at lower levels.

The success of the Commission's decisions in the proceeding and the consequences of an RPS for New York's citizens and businesses will depend on how successfully the Commission harmonizes these competing or conflicting objectives. No aspect of an RPS should have the potential to undermine a utility's opportunity to recover all prudently-incurred costs. Utilities should not be expected to supported a program that has the potential of harming them financially. The RD now before the Commission does not generally attempt to resolve issues with reference to the Commission policies noted above. The RD (p. 1) apparently sought a "balance" between various positions of parties on individual subjects, rather than seeking outcomes that balance the policy objectives and implementation approaches of an RPS with other important Commission policies and objectives. That approach represents an opportunity missed.

The Joint Utilities believe that a fundamental error in the RD lies in its adoption of a flawed premise: that individual LSEs should be responsible for RPS compliance. LSEs should simply be conduits that facilitate the funding of the RPS; and a third-party entity (whether a State agency, the NYISO, or other entity) should be responsible for RPS compliance. By proceeding on the assumption of LSE RPS compliance responsibility, the RD effectively disregarded the Joint Utilities' alternative Central Procurement Model, which, at its most basic level, appropriately places RPS compliance responsibilities in a qualified and adequately-funded third party, and requires all LSEs' customers to fund the third-party's compliance obligations — much like the SBC.

In the Joint Utilities' view, the RD is further driven by another flawed premise: that mandatory long-term contracts, together with imposition of specific "targets" on LSEs, are necessary to finance renewables. While the Joint Utilities do not agree that long-term contracts are necessary, even if one were to assume they are, it simply does not follow that such commitments need be made by individual LSEs. Making that assumption obscures an essential distinction, perhaps *the* essential distinction, between the so-called "individual compliance model" and the "central procurement model" discussed in this proceeding.

Both "models" are premised on deriving financial support from revenue streams derived from retail customers. In the Individual Compliance Model, the LSE's prices would reflect the costs of contracts between the LSE and the renewable developer. In the Central Procurement Model, the LSE's prices would include an element that would be collected by the LSE and transferred to the central procurer (much like the SBC charge), which would in turn utilize that "revenue stream" to support any needed contracts (or alternative financial arrangements) with developers. The ultimate responsibility of funding the RPS devolves in both cases to the customers of the LSEs. The essential distinction between the two is which entity enters into financial obligations with the renewables developer.

The failure of the RD to perceive that essential distinction led apparently to the recommendation in favor of Staff's so-called "hybrid model," itself a misnomer because Staff's model places responsibility for attaining renewables' "targets" on individual LSEs and is an Individual Compliance Model at its core. It appears that much of the RD is premised on that fundamental misconception, and there is no reason set forth in the RD for not recommending a "central procurement" approach. The Central Procurement Model levels the playing field among LSEs, ensuring compatibility with retail competition and guaranteeing that all market participants are treated equally and fairly. It minimizes duplicative costs associated with individual compliance, promotes price transparency, ensures all New York State energy consumers will pay the same equitable price for the RPS, reduces the risk of market power abuses, avoids creating financial problems due to load shifting, and can be quite flexible and adaptable. The RD has refuted none of these advantages.

No matter how the Commission resolves the parties' exceptions, inevitably some period of time will be needed for the "implementation phase," followed thereafter by implementation. The Joint Utilities had proposed a different, more expeditious, and productive path: immediate implementation of a central procurement pilot. This proposal was barely mentioned in the RD. The Joint Utilities' intent was that pilot development commence promptly. If the Commission now were to "fast-track" development of the pilot, enlisting the participation of an appropriate State body "central procurer," the Joint Utilities see no reason why that State body could not acquire renewables resources as soon or sooner than any other approach, and without prejudicing the Commission’s consideration of exceptions or delaying the RPS. Accordingly, the Joint Utilities urge the Commission to consider immediate authorization of a pilot program.

This Brief on Exceptions presents the Joint Utilities' exceptions with respect to RPS design, procurement issues, reliability, standards applicable to utility resource acquisition or future regulatory determinations, cost studies, and other RPS parameters. The Joint Utilities recommend the central procurement approach, on the grounds that it offers all of the advantages of individual compliance, and none of the disadvantages, and can produce efficiencies unattainable under individual compliance. We oppose mandatory long-term contracts because they have not been shown on the record to be necessary, they are not actually necessary as a general proposition (although they may be warranted in limited cases, particularly for the smallest facilities), and historically they have been shown to have disadvantaged all interested parties. We recommend that the Commission confirm that reliability is the paramount policy objective. We submit that the cost studies done so far based on the Staff modeling approach are not sufficient for decisional purposes (contrary to the unsupported conclusion of the RD), that exclusion of post-2013 costs is erroneous, that other modeling errors are incorporated in the Staff approach, that the RD failed to consider the alternatives that had been previously identified in the Draft Generic Environmental Impact Statement ("DGEIS") from a cost/benefit or any other discernible perspective, and that the reliability-related costs have not been identified.

In addition, the Joint Utilities:

- Explain the substantial harm that contracts-for-differences ("CFDs") could do to New York State as an RPS purchase mechanism,
- Describe why an alternative compliance mechanism ("ACM") is unnecessary and undesirable under any procurement model, and in 2006 in particular,

- Recommend that the Commission fix the RPS milestone requirements for each year at the values set on Table 1 in Appendix B for each LSE,
- Identify the importance of specifying that the object of RPS compliance should be the acquisition of attribute certificates unbundled from energy,
- Explain why a deliverability requirement is unnecessary and undesirable, and incompatible with a regional market,
- Recommend that customers of NYPA, municipals/municipal public power entities, and "very small" ESCOs be required to fund their fair share of the costs of the RPS,
- Address the matter of resources which should qualify for RPS premiums,
- Point out clearly why tiers are not justified in the New York RPS program, and
- Describe why resources receiving other subsidies should not qualify for RPS premiums.

The details of our exceptions are discussed below.

The Joint Utilities recommend that the Commission issue an RPS Policy Statement consistent with the positions raised in this Brief on Exceptions to allow implementation of an RPS to move forward. Specifically, the Joint Utilities propose that the RPS Policy Statement address basic RPS policy parameters (*e.g.*, the model design). The RPS Policy Statement should be sufficiently flexible to accommodate remaining reliability and cost analyses, as well as identification of implementation matters.

EXCEPTIONS

I. RPS DESIGN

The RD (p. 75) recommends "the hybrid central procurement model proposed by Staff. . . . ." In the Staff "hybrid," LSEs are the entities responsible for RPS compliance, and LSEs could permissibly select optional implementing mechanisms[1] for meeting their RPS obligations.[2]

The Joint Utilities are hopeful that the Commission will demonstrate its commitment to fostering the development of renewables consistent with consumers' interests in the lowest reasonable costs and the other policy objectives described above. This goal can be achieved through a clear endorsement of the Centralized Procurement Model, using a State procuring body (to the extent that the NYISO is unwilling to serve the function) to enter into such long term financial commitments with renewables developers as the procuring entity may determine are advisable,[3] that will be funded by the customers of LSEs. Accordingly, the Joint Utilities except to the RD's recommendation to require individual LSEs to meet annual RPS target obligations.

The RD (p. 68) acknowledges that a "central choice in the design of an RPS concerns the overall structure: should the procurement of renewables be through some centralized mechanism, or by individual load serving entity?" However, the RD never addresses this issue. There is no discussion in the RD that analyzes the relative merits of individual, LSE-by-LSE apportionments of an overall statewide RPS target, as compared with placing the responsibility for attaining RPS targets in a State body and establishing the supporting mechanisms that would enable that body to accomplish the mission of the RPS successfully and consistent with consumers' interests in lowest reasonable costs. The RD's discussion of "Individual Compliance" (pp. 68-73) does not compare these alternatives. Nor does the "Individual Compliance" portion of the RD expressly recommend

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1 As stated in the RD: "[T]these options, including procurement through a central State agency broker, neither require nor preclude utility [or, presumably, other LSE] construction or ownership of renewable generation" (Appendix C, para. 5).

2 As phrased by Staff in its September 26, 2003 "Initial Comments," p. 22 (Staff footnote omitted): "While Staff supports placing the burden of compliance on individual LSEs, it also supports allowing LSEs to make a competitive business decision to opt in to a cooperative central procurement system that could be implemented by a state entity such as NYSERDA [New York State Energy Research and Development Authority]."

3 It need not be assumed that long-term supply contracts are the only possible mechanism for funding the financing of renewables. *See* Central Hudson Reply Comments, pp. 9-13, for a discussion of some possible alternative financing approaches.

the Individual Compliance Model. Nevertheless, the RD adopts the Staff "hybrid" version of the Individual Compliance Model and recommends individual compliance by implication through its adoption of the "alternative compliance" penalty mechanism (p. 23).

As noted in the Summary, this approach appears to have been driven by the assumption that placing the "burden of compliance" on individual LSEs was needed, along with mandatory long-term contracts between LSEs and developers, to finance renewables, and by a misperception of the essential distinction between central procurement and the "hybrid" individual compliance model recommended in the RD.

A "centralized mechanism" offers significant advantages as compared with individual LSE purchase obligations, as the Joint Utilities have discussed in their Initial and Reply Comments (Attachment B, pp. 11-15; Attachment C, pp. 21-42). The centralized procurer can develop a coherent strategy for soliciting various "blocks" of renewables that match the ability of the markets to deliver rather than the per LSE allocation of a schedule of annual "targets."[4] A State body acting as the centralized procurer[5] on a State-wide basis can also give coherent consideration to geographical distribution of renewables, any appropriate encouragement of specific technology types and to other factors related to State policy that would not be relevant to, or available for consideration in, procurement by an LSE having a basic desire to seek "least cost" alternatives.

By its basic structure, a Central Procurement Model avoids a number of the problems that are created by the RD's recommended imposition of an individual, LSE-by-LSE compliance

4 The Joint Utilities believe that the centralized procurement may best be accomplished through an auction, but recognize that the centralized body may prefer that a carefully developed Request for Proposal ("RFP") be used. Properly designed, economically desirable and otherwise sound results could be achieved from either alternative.

5 The centralized procurer need not necessarily lead to growth of State workforce. A "board" much like the former Siting Board could be established, and any required financial obligations could be entered into through the New York State Energy Research and Development Authority ("NYSERDA") or some other State agency. Minimal, if any, additional personnel would appear to be required given the existing panoply of expertise available from Staff and NYSERDA.

structure. For example, how is customer switching and ESCO customer dropping addressed? Are renewable energy and/or credits somehow transferred from an ESCO to a T&D utility that now must serve a former ESCO customer? Or must that T&D utility procure incremental renewable energy and/or credits for customers who, next month, may switch to another LSE? When a T&D utility has committed to pay for renewable certificates based on a given load that has now shrunk because of customer migration, are these "stranded" costs? If the T&D utility had entered into a long-term (inappropriately defined in the RD (p. 23) as eight or more years) contract for these certificates, would the costs still appear as a wires charge on the remaining customer base despite customer migration? Is the utility at risk of disallowance for the costs of multi-year contractual undertakings in compliance with a Commission allocation of RPS “targets” to last year’s load if future loads are reduced by customer migration? The central procurement approach avoids these difficulties by addressing RPS "targets" on an overall, state-wide basis that reduces the effect of the individual changes in customers, ESCOs and load/resource imbalances that occur more prominently on a utility-by-utility basis. Central procurement also provides more flexibility in the development of resource acquisitions on an annual or other timeline basis, taking market developments into account.

Conversely, no legitimate reason exists for requiring that LSEs exclusively undertake the purchase obligations for the RPS program. The historical models (PURPA and NY’s six cent law) were economic failures from customers’ and utilities’ standpoints.

The closest to an argument for individual compliance is that it has allegedly worked elsewhere. The RD (p. 74) describes the individual compliance method as “the only one with a track record from other states to draw upon.” The fact, however, that an individual compliance method may have been used in other states has no bearing on whether alternative models could be equally or more successful in New York. That contention ignores the specific regulatory policies that have been adopted in New York State, and the creativity of the Commission and interested parties in fashioning solutions that serve the particular needs of consumers in this State.

The Central Procurement Model is much more compatible with the successful development of retail competition than the Individual Compliance Model, because it effectively levels the playing field among LSEs for this regulatory mandate. Individual compliance can be expected to entail “lumpy” acquisitions by individual utilities and consequent “lumpy” changes up or down in the revenues needed to fund those requirements, artificially creating an appearance of potential advantages for some LSEs over others and disadvantages for ESCOs and customers. Individual compliance also risks complicating the customer switching process, hindering the ability of ESCOs to make business choices to enter or leave markets, and confusing the relationship between ESCOs and T&D utilities. The "hybrid" model as proposed by Staff does not resolve any of these problems; in some ways, it merely offers an opportunity for additional complications (*see* Section II (A) for a discussion of the implications of long-term contracts under Staff's hybrid model).

In contrast, central procurement allows the regulatory objective of facilitating commercialization of renewables to be achieved by the central procurement entity (whether a State agency or some other body). LSEs retain only the responsibility to fund their fair share of the purchases made by that entity — in the case of utilities, by "flowing through" to the central procurer the revenues collected from customers as approved by the Commission. No LSE is advantaged; no LSE is disadvantaged. All LSEs are treated equally. Further, it is far more in customers’ interests to drive down costs by establishing a centralized procurement system in which renewables developers are competing with each other for access to the RPS premiums dispensed through the central procurer, rather than to require LSEs to compete with each other to obtain annual increments, which will tend to drive up the costs of the RPS program to retail customers.

The Commission has made it quite clear that both the RPS and retail competition are high policy priorities. Only the Central Procurement Model, operating flexibly to develop variable resource acquisition amounts, at times warranted by market conditions, and funded through the mechanism described above to assure that the central procurer's obligations are fully met, will allow both priorities to be met equally well. The Individual Compliance Model precludes LSEs from receiving revenues for renewable acquisitions until after they have been entered into. In contrast, the Commission could decide to provide for advance funding before the central procurement body has issued its first auction or competitive solicitation, just like the Commission did for the SBC charge, for the purpose of spreading the funding over as long a time period as possible and minimizing the size of the increment.

No matter who is ultimately determined to be responsible for procurement, the successful funding of RPS premiums will not be attained unless the Commission supports the RPS program. If the Commission commits to supporting the RPS program by, for example, establishing the appropriate charges, there should be no reason why a State body would have any risk in entering into whatever financial commitments are found to be desirable to facilitate financing. There should be no reason to ask utility and other LSE shareholders to assume such risk.

The RD does not affirmatively recommend that the State designate an agency to assume responsibility for procuring renewable resources, whether under the hybrid model or under the Central Procurement Model. The absence of a recommendation for the designation of a State body should be contrasted with the presence of a recommendation for imposition of the "burden of compliance"[6] on private LSEs. The Joint Utilities believe that the Commission should expressly designate some body (other than LSEs) to be responsible for RPS compliance under the Central Procurement Model.

II. PROCUREMENT ISSUES

While the primary focus of the RD should have been on the responsibility for RPS compliance, the means by which renewables are acquired (and the consequences of non-compliance) must also be considered. As explained below, the RD's discussions of long-term contracts, CFDs, and an ACM contains fatal flaws.

A. The RD Errs with Respect to Its Promotion of Mandatory Long-Term Contracts

The RD (p. 75) states that the central procurement "approach entails the State agency issuing a competitive solicitation for eligible renewable attributes and choosing the winners, similar to the current SBC grant program. The State agency would *need* to enter into long-term contacts for some significant portion of the attributes" (emphasis added). The conclusion that long-term contracts are actually necessary was not supported by analysis.

For the reasons set forth in the Joint Utilities' Reply Comments (Attachment C, pp. 50-51), mandatory long-term contracts should be rejected as a matter of public policy. Moreover, contrary to the implication in some parts of the RD (p. 75), the RD correctly observes elsewhere (p. 87) that there was no consensus even among renewable developers (the intended beneficiaries of long-term contracts) that long-term contracts were necessary. During the various "collaborative" discussions, while some parties largely representing the smallest potential developers did assert that such contracts were "necessary," other developers of commercial scale renewable projects strongly disagreed and stated that they could and did finance projects under existing ISO markets

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[6] *See* n. 2 *supra.*

without long-term contracts with utilities. The RD does not discuss these divergent views in any analytical fashion. The central procuring body should be accorded the opportunity of deciding how best to make its solicitations, including consideration of alternative financing methods. Furthermore, the central procurer may decide that it will permit parties participating in the solicitations to propose alternative financing arrangements, as part of an effort at reducing the costs of acquisition while furthering commercialization of renewables by seeking creative solutions from the market participants.

In the current marketplace, ESCOs have the right to enter and leave utility service territories as they wish and their business plans dictate. ESCOs may gain and lose customers from month-to-month and from one incremental RPS year to another. Customers may similarly switch from ESCOs to utilities and back again. As a result of these load shifts, the megawatthours ("MWH") associated with the percentages on Table 1 for each LSE will vary over time whether the LSE allocates its entire target to the State agency or opts for individual procurement under the RD's hybrid model. The burden of matching loads and resources falls much more heavily on entities like ESCOs and T&D utilities. Thus, the requirement that ESCOs and T&D utilities enter into long-term contracts is particularly inappropriate.

B. CFDs Are an Unacceptable Mechanism for RPS Compliance Under Any RPS Design

The RD effectively requires LSEs to meet their RPS targets using CFDs. In adopting Staff's proposal for CFDs, the RD (p. 87) states:

> Staff proposes bidding on renewables certificates, based on a contract for differences approach, reflected in its cost studies. In Staff's view, this approach resembles both MI's and ConEd Solution's, and caps payments to generators by capping MWhs purchased under each contract. Staff suggests a functional revenue cap could be achieved with symmetrical contracts for differences.

The RD fails to address the concerns of various parties that pointed out the dangerous side effects on the wholesale market and system operations of the particular form of CFDs that has been discussed in this proceeding. For purposes of these comments, the Joint Utilities will call this form of CFDs "hybrid CFDs" to indicate that they are a very particular type of generic CFD instrument. The Joint Utilities strongly oppose the use of these hybrid CFDs under any model: central procurement, individual compliance, or hybrid.

A generic CFD is a contract for a product or service in which the buyer agrees to pay the seller the difference between a pre-agreed fixed price and a known or observable variable price. This payment can be negative (*i.e.*, the seller would pay the buyer when the observable variable price exceeds the fixed price). It is usually used as a risk management tool, and it protects the buyer and seller from the difference between the fixed price and the variable price.

Under a hybrid CFD, the fixed price is either the bid price or the market-clearing price of bundled energy and attribute certificates, and the variable price is the LBMP price of electricity.[7] Under these contracts:

Generators receive their total CFD price regardless of the LBMP price of energy. For the life of the contract, the LBMP price for the generator's LBMP zone will have no effect on the generator's revenue. It becomes the responsibility of the State agency or LSE to make up the difference between the LBMP price and the CFD price.

The price of attribute certificates will vary on an hourly basis. For the life of the contract, the price of the attribute certificate will be the difference between the fixed CFD price and the day-ahead or real-time hourly LBMP price for the LBMP zone.

LBMP market signals will go to the renewable buyer, not the renewable generator. For the life of the contract, LBMP market price signals that are intended to cause generators to increase or decrease their output will go to the State agency or LSE. The State agency or LSE, of course, does not have day-to-day authority or control over power plant operation, and is unable to respond to those price signals.

Generators can be expected to push energy into the wholesale market in an uncontrolled way. For the life of the contract, the generator has no economic incentive to generate power at any particular

[7] MI proposed a slight variation on this form of the hybrid CFD. The Joint Utilities oppose the MI CFD variant as well. MI proposed a hybrid CFD that "would be the difference between the payments received by the facility from the NYISO for energy, capacity and ancillary services and the facility's cost of service." MI Initial Comments, p. 23.

time during the day or year, or to reduce generation at any particular time during the day or year. The generator's only apparent economic incentive is to maximize the production of energy and associated attribute certificates to create new revenue streams. This result could cause these generators to dominate the market in some locations and during some periods, particularly off-peak periods, creating highly volatile energy prices, forcing uneconomic accommodations by backing down or dumping existing baseload generation (*e.g.*, existing hydroelectric), and encouraging the retirement or shutdown of generating capacity that is needed during other periods, especially on-peak.

NYISO may be required to intervene to maintain system reliability. In the extreme, the NYISO can direct these renewable generators to increase or decrease output for reliability reasons. The retirement or shutdown of existing generation capacity can also be prevented in various (expensive) ways if necessary. It would be more desirable, of course, to allow the market to act as designed to prevent the need for such intervention.

The Commission's RPS Policy Statement should discourage any form of contract or RPS purchase mechanism that shields the generator from LBMP market signals. Generators should be motivated to locate their units where LBMP prices are highest. If LBMP prices go down, generators should be motivated to reduce output; if LBMP prices go up, generators should be motivated to increase output.[8]

The desirable result of sensitivity to the LBMP market is most likely to occur if parties contract solely for attribute certificates, independent of the price of energy and capacity, and if renewable generators sell their energy and capacity separately. This approach will also facilitate the RPS purchase process; it will be much easier to fairly compare bids in response to an RFP or descending-clock auction[9] if those bids include only the price of the certificates, and if that price does not require the buyer to correct for or forecast zonal LBMP prices. Specifically, the rules of the RPS should not encourage the price of certificates to vary on a real-time basis inversely with

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8 This is one of the important uses of the secondary certificates market, and one of the reasons for the Commission's RPS Policy Statement to encourage banking and borrowing functionality. Generators should be encouraged to purchase and sell certificates on the secondary market to avoid the need to generate at inappropriate times to meet their RPS contract requirements. Out-of-state generators should be able to participate on the secondary market as well. This will be one of the useful aspects of eliminating a delivery requirement – it encourages a liquid secondary market in certificates, which in turn fosters stable certificate prices and encourages renewable generators to pay attention to the traditional wholesale market as a significant source of revenue.

9 A descending-clock auction is described in the Joint Utilities' Initial Comments, Attachment B, pp. 17-20.

prices on the LBMP market, thereby transferring the risk and responsibility for responding to LBMP price signals to the buyer of the attribute certificates.

C. The RD Record Fails to Justify the Need for an ACM under Any Model

Without any explanation, the RD (pp. 23, 72; App. C, para. 9) recommends imposition of an ACM penalty on any LSE that has "not procured its target percentage of renewable generation in a given year." The ACM would be "150 percent of the past year's certificate cost" (p. 23).

Moreover, the RD recommends that the ACM would apply even if the LSE's failure to meet RPS targets were due to *force majeure* events beyond the LSE's control, such as the failure of an RPS-eligible resource to be developed (p. 72). There is no reasoned basis for establishing any penalty or enforcement mechanism applicable to such circumstances.

An ACM simply has no role in a Central Procurement Model, or under the RD's hybrid proposal where a State agency is the procuring entity. If the entity managing the centralized procurement process has made a good faith effort and is unable to acquire sufficient renewable resources, this indicates such resources are unavailable at a mutually-agreed upon price. Under these circumstances, the annual target should be shifted to a later year, and this change should be noted in the annual report to the Commission. Utility LSEs remain subject to after-the-fact review should they fail to operate prudently, and the good faith of a State body central procurer can be presumed. There is, therefore, no real justification for presuming the absence of good faith, particularly in the absence of any viable renewables market today and uncertainty about how, when, and under what economic conditions one may exist in the future.

In an Individual Compliance Model and in connection with the individual procurements contemplated under the hybrid model, an ACM would also be unjustified (as noted above) and unwise, in part, because it would be difficult to determine prior year certificate prices to calculate the value of the ACM. In practice, individual, bilateral procurements would involve private pricing terms. Sales and purchases of certificates may occur under varying conditions at different times of year, through RFPs using different criteria, through various auction forms, in different geographic locations, or through secondary markets. Further, hybrid CFDs will produce attribute certificates with prices that change from hour to hour during the year, based on the individual bid price of the resource and the zonal LBMP price. Calculating the "cost" of certificates for ACM purposes will be quite contentious under these circumstances.

For attribute certificates to have a single, clear price with little variability during the year or from location to location in New York State, the market for attribute certificates must be efficient, liquid, and price-transparent. This situation will not occur until these certificates are bought and sold in quantity, in a consistent form, and the prices are routinely revealed and equally consistent throughout the State. Looked at another way, such a market will have been created only when a party that owns too many certificates, or not enough certificates, can easily sell the excess or buy to fill the gap at any time, in any reasonable quantity, and at a predictable price. At the very least, these requirements would seem to demand an RPS that is focused on real-time certificate sales and acquisition, that does not mandate long-term contracts, and that fully separates energy and capacity markets from the certificates market, eliminating such mechanisms as hybrid CFDs from consideration.

The suspect logic of an ACM can be seen by considering the initial year. If the Commission decides to adopt an ACM, it is obvious that no 2005 renewable certificates will be "delivered" in New York State if the RPS program does not begin until 2006. Thus, just at the time that the policy behind an ACM is presumably intending to produce activity to acquire renewables, the mechanism precludes determination of the ACM amount. Conversely, in later years, after the markets have developed, there is less presumptive need for an ACM, yet the calculation of the penalty would be more feasible. To implement an ACM in 2006 as proposed in the RD, the Commission must address how the charge would be determined that year since no certificate cost history will be available.

Finally, an LSE should be exempt from any ACM responsibility during the initial year(s) of the RPS program, assuming that there is no basis for challenging the LSE's good-faith effort to meet any then-applicable RPS program requirements. As indicated above, an ACM should never be applicable when the failure to meet the ACM is based upon circumstances outside the LSE's control.

III. RELIABILITY

A. The RD Should Have Ratified the Paramount Importance of Reliability

The Joint Utilities have specifically recommended in their Initial Comments (Attachment B, p. 6)[10] that the Working Objectives be clarified so that the reliability of the New York State transmission system is recognized as the paramount policy consideration in the RPS proceeding. Stating (p. 36) that it was "strengthening the reliability language," the RD (pp. 34-37) provides a revised Working Objective 2, Generation Diversity, "to stress security and ensure reliability, as recommended by the NYISO." As proposed in the RD (p. 37), Working Objective 2 now reads:

> 2. <u>Generation Diversity for Security and Independence</u>
>
> Diversify the generation resource mix of energy retailed in New York State to improve energy security and independence, while ensuring protection of system reliability.

The RD's recommendation does not equate to the explicit recognition of reliability as the paramount policy objective that the Joint Utilities continue to believe is desirable and, indeed,

10 *See also* Joint Utilities' Reply Comments, Attachment C, p. 7; Central Hudson Comments, p. 10.

necessary. There is no apparent reason why the addition of a seventh[11] "working objective" expressly recognizing the paramount importance of reliability would be inappropriate. The Commission must find that the safe and reliable operation of the State's transmission system is the critical policy goal. This finding is required not only because of the inherent significance of a reliable grid to public safety, but also because, without a reliable grid, Working Objective 3, "Economic Benefits," Working Objective 4, "Equity and Economic Efficiency," and Working Objective 5, "Competitive Neutrality," would not be met. The RD's inclusion of the need to protect system reliability within Working Objective 2, rather than creating a separate Working Objective, does not recognize that transmission system reliability is the paramount policy consideration in this proceeding. Increased generation diversity using intermittent resources does not necessarily equate to improved energy security and independence. In fact, it may result in an increased dependence on traditional fossil and hydro generation to balance supply and demand.

The RD's recommendation is also inconsistent with its stated intention of "strengthening" the significance of reliability. The mere addition of a reference to protection of system reliability does not sufficiently strengthen the Working Objectives language such that transmission system reliability is recognized as the paramount policy consideration in this proceeding. In fact, as recommended, the RD's revision is counter-productive because it makes generation diversity the active objective and reliability subordinate to diversity. The Joint Utilities thus except on the primary ground that the RD should have specifically and clearly endorsed the paramount nature of reliability among the objectives, and on the secondary ground that the RD's language is inconsistent with its stated intent.

Given the RD's short treatment (p. 93) of the parties concerns with relying on the Phase I Reliability Report, *The Effects of Integrating Wind Power on Transmission System Planning*,

[11] *Cf*: RD p. 36.

Reliability, and Operations (issued February 2004), it is, at best, questionable whether the proposed Working Objective clarification does, in fact, reflect a recognition that transmission system reliability is the paramount policy consideration in this proceeding.

B. The RD Errs in Failing to Emphasize That the Commission Should Not Conclude the RPS Proceeding until after the Phase 2 Reliability Report Is Issued

The RD (p. 93) summarily concludes that the "Phase 1 Report provides sufficient certainty to proceed with the RPS design" and that "the Commission will have the benefit of the Phase 2 Report in time for any implementation." The RD, however, fails to address the parties' positions on this issue, some of which are reviewed in the RD (pp. 90-93). As stated in the Joint Utilities' Initial Comments (Attachment B, p. 3) and the Joint Utilities' Reply Comments (Attachment C, p. 7), reliability is of paramount importance. The importance of reliability has also been emphasized in the Initial Comments of many other parties.[12] The RD's recommendation that the Commission proceed with the final design and implementation of the RPS in New York State before the Phase 2 Reliability Report is issued demonstrates that the paramount importance of transmission system reliability has not been properly acknowledged in this proceeding.

As stated in the Joint Utilities' Comments on the Phase 1 Reliability Report (Attachment E, p. 3), the Phase 1 Reliability Report is only a preliminary report that does not attempt to reach quantitative conclusions. The Phase 1 Reliability Report makes a series of inconclusive and qualified statements that will be further evaluated in late 2004, when the Phase 2 Reliability Report is expected to be issued.[13]

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12 MI Initial Comments pp. 8-11; NYISO Initial Comments p. 4; AES Initial Comments p. 1; NYSRC Initial Comments pp. 1-2; Nucor Steel Initial Comments pp. 1-2; UWUA-IBEW Initial Comments p. 2; CPB Initial Comments pp. 4-5; Central Hudson Initial Comments pp. 10-11; KeySpan Initial Comments p. 5; and AG Initial Comments p. 13.

13 On this point, the Joint Utilities support the Written Exceptions being submitted by the New York State Reliability Council.

Conspicuously absent from the RD's discussion of the parties' comments on the issue of RPS reliability impacts is a discussion of the Comments of the NYISO on the Phase 1 Reliability Report. The NYISO, jointly with NYSERDA, commissioned the Phase 1 Reliability Report and Phase 2 Reliability Report studies. Moreover, NYISO is the entity in New York State primarily responsible for maintaining transmission system reliability. Therefore, the NYISO's comments and views regarding the Phase 1 Reliability Report should have been fully acknowledged and followed in the RD's recommendations. The RD's failure to do so represents a fundamental flaw.

While the NYISO recommended that the Commission continue to move forward on basic infrastructure issues such as portfolio design, funding mechanisms, eligible technologies and the policy issues that would allow the parties to proceed with the development of a Generation Attributes Trading System ("GATS"), the NYISO also recommended that the Commission make only preliminary decisions on these issues in order to assist the parties in fully evaluating the RPS with all its attendant details following the issuance of the Phase 2 Report (NYISO's Comments on the Phase 1 Report, p. 1). The NYISO unequivocally and repeatedly advised the Commission not to conclude the RPS proceeding until after it receives comments from the parties on the issues that will be addressed in the Phase 2 Reliability Report (NYISO's Comments on the Phase 1 Report, pp. 2, 4, 7). Echoing the Joint Utilities' concerns (Attachment E, p. 4) that the Commission will not know the reliability and related cost impacts of implementing an RPS in New York State until after the Phase 2 Reliability Report is issued, the NYISO stated that the Phase 2 Reliability Report will provide the further analyses intended to help the Commission avoid unintended, adverse economic consequences. Moreover, the NYISO cautions (NYISO's Comments on the Phase 1 Report, p. 2) that firm conclusions in the crucial reliability area cannot be made until the conclusions of Phase 2 are reviewed and analyzed.

In their Reply Comments (Attachment C, pp. 8-9) the Joint Utilities urged the Commission to allow sufficient flexibility in its determinations regarding the design of the RPS program to address the findings of the Phase 2 Reliability Report. Given the paramount importance of reliability, such flexibility is essential so that the Commission can not only update the record in this proceeding, but may also revisit, and adjust as necessary, certain aspects of the RPS program design, consistent with the information that the Phase 2 Reliability Report ultimately yields.

The RD (pp. 30-32), however, concludes that the record (which does not as of this date include the Phase 2 Reliability Report) is a sufficient evidentiary basis for the Commission to issue an RPS Policy Statement “concerning fundamental RPS program initiation and design” (RD p. 30). While the RD purports to provide a flexibility mechanism built into the RPS policy (p. 39), the RD (pp. 48, 75) recommends that the first RPS milestone review year be set for 2008, four years after the issuance of the Phase 2 Reliability Report and two years after the start of the RPS program. This recommendation does not provide sufficient flexibility for the Commission to address the findings of the Phase 2 Reliability Report. Rather, the RD, ignoring the NYISO’s and the other parties’ admonitions, concludes that the record is sufficient as it stands.

IV. FAILURE TO IDENTIFY THE STANDARDS APPLICABLE TO UTILITY RESOURCE ACQUISITION OR FUTURE REGULATORY DETERMINATIONS

As noted in the RD (pp. 34-35), the Working Objectives recommended for adoption include the proposal that an RPS should "afford[] opportunities for recovery of utility investment." The RD (p. 75), however, qualifies this objective by proposing that utilities must enter into "prudent and competitively-obtained long-term contracts . . . for renewable resources to comply with the RPS. . . . " These statements are so generalized and lacking in articulated standards that utilities subject to them do not have sufficient notice of the standards to which they will be subject.

The core of the problem is that one of the guiding principles of prudence revolves around least-cost acquisition, but acquisition of renewables under an RPS requires purchase of resources that, by definition, are not “least cost.” The utility could purchase the "least cost" RPS generation and could subsequently be found imprudent if a future reviewing body were to determine that the utility paid excessive costs for above-market RPS resources.

A second dimension to the problem lies in the reliance in the RD (p.25) on *Energy Association of New York State v. Public Service Commission*[14] for the proposition that the Commission can “direct a specific portfolio.” It must be observed that the question of authority is a different matter from the question of advisability, and the RD seeks to determine an advisable course of action. Moreover, that case was, in fact, decided on a narrow procedural ground. All of the substantive discussions therein rise to no more than dicta with no precedential value. That case has been asserted to also stand for the proposition that the Commission has authority to disallow even prudently incurred costs, after the fact. If the Commission so construes its authority, it is asserting both the power to require a utility to enter into a long term contract and the authority to disallow the costs of the contract it directed. The Joint Utilities request that the Commission’s consideration of this matter clarify that the Commission does not assert the authority to disallow the costs of contracts entered into in compliance with an RPS program directed by the Commission. It is particularly necessary that the Commission provide this clarification because RPS contracts are, by definition, uneconomic when entered into.

Furthermore, the Working Objectives do not provide adequate assurance to utilities that they will receive recovery for the cost incurred in connection with an RPS. While the Joint Utilities recognize that such recovery is only permitted for prudent expenses, the Commission's policy statement should affirmatively provide that utilities will be entitled to recover prudently-

[14] 169 Misc.2d 924 (Sup. Ct., Albany Co. 1996), *aff'd*, 273 A.D.2d 708 (3d Dept. 2000).

incurred costs. The distinction between the language in the Working Objective and that proposed here is not merely semantic. It must be clear that the utilities will receive current cost recovery, subject to a subsequent demonstration of imprudence, rather than offering the utilities no more than an ambiguous possibility of such cost recovery.

The Joint Utilities' proposal is consistent with the accepted standard governing recovery of prudent expenses incurred in the legitimate operation of their businesses. The courts have repeatedly held that utilities generally are entitled, as a matter of law, to recover prudently incurred costs. *See, e.g., Abrams v. PSC*, 67 N.Y.2d 205, 217, 492 N.E.2d 1193, 1199, 501 N.Y.S.2d 777, 783 (1989) (noting that "a regulated company is generally entitled to recapture its prudently incurred costs, including a return on its investment . . .") (quoting *Rochester Gas & Elec. Corp. v. PSC*, 108 A.D.2d 35, 37, 488 N.Y.S.2d 303, 305 (3d Dept. 1985)). Further, the following statement from Justice Brandeis's concurring opinion in *State of Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission*, 262 U.S. 276, 289, n. 1 (1923) is often cited in discussions of prudence: "Every investment may be assumed to have been made in the exercise of reasonable judgment, unless the contrary is shown." Consistent with this pronouncement, a 1985 report prepared by the National Regulatory Research Institute[15] offered the following: "A mere allegation of imprudence may not be sufficient to rebut the presumption of prudence; rather, an allegation of imprudence must be backed up by evidence that is substantive and that creates a serious doubt about the prudence of the investment decision."

In its RPS Policy Statement, the Commission should explicitly authorize utilities to track and immediately recover all incremental costs incurred to comply with the RPS. In connection with the utilities' pass-through of their respective share of RPS program costs to customers, the

[15] Burns, THE PRUDENT INVESTMENT TEST IN THE 1980S, 56. The National Regulatory Research Institute was established in 1976 by the National Association of Regulatory Utility Commissioners.

Joint Utilities recommend that such recovery be expressly allowed on a current basis with the method determined during the Implementation Phase based on the procurement model adopted by the Commission in its RPS Policy Statement. Given the State-mandated nature of the costs, it would be appropriate that the RPS program cost element be a separate surcharge visible and transparent to customers.

Because utilities will be held to a prudence standard with respect to cost recovery, it is particularly important that the Commission establish clear guidelines with respect to RPS design parameters (especially those discussed hereafter in Section V (E), "Requisite Additional Cost Analyses") before the utilities are required to act. It is unreasonable to expect the Joint Utilities to take actions consistent with the rules to which they will be subject (and tested for prudence) until the Commission clearly articulates the parameters of the RPS. The need for clear direction is particularly critical in light of the ambitious schedule that the RD contemplates. Because many actions that may be necessary require long lead times (*e.g.*, long-term contracts, building renewable resources, design of an attribute trading system, and other implementation matters), the Joint Utilities face the unreasonable dilemma of being found imprudent for taking a specific action (when such action is later determined unnecessary) or failing to do so (when later action is deemed to have been necessary). Thus, the Commission must provide the Joint Utilities with sufficient direction, and sufficient time to implement that direction, before invoking any prudence analysis.

V. COSTS

A. Background

From the inception of this proceeding, many parties have expressed concerns about the potential amount of extra-market revenues that would be provided to eligible renewable generators and whether the payments to the renewable generators would be limited to those actually "needing" the extra-market revenue stream. Consideration of these issues did not commence, however, until mid-2003, at which time Staff (with the assistance of several Massachusetts-based consultants) and the Joint Utilities[16] each submitted initial cost studies. These studies related to an assumed incremental RPS requirement ("target") of eight percent, derived from an April 28, 2003, RPS targets spreadsheet that had been circulated to the parties by Staff. Load growth and a number of other relevant assumptions for both studies were taken from the last State Energy Plan ("SEP2002"), defining a similar "reference case" for both studies.

The analytical methods of the two studies differed. Staff (and its consultants) employed two separate models, a "Supply Curve" model and General Electric's proprietary MAPS program, in an "iterative" fashion, intending to produce a solution that converged between the two models. The Joint Utilities' Study was done by ICF Consulting, a highly qualified analytical group with significant, direct New York experience, using its proprietary Integrated Resource Planning Model® ("IPM"), a well-known analytical tool employed by numerous governmental (including New York State) and private entities particularly suited to the intermediate to long-term analysis of economic/regulatory policy proposals such as that presented here.[17]

In addition to these "structural" differences in modeling approaches, the initial studies differed in the parameter that was studied, in the time period of the analyses, and in the definition of the "cases" that were studied. Staff chose to determine the financial impact of the proposal on New York electric customers (direct RPS premium costs less forecast wholesale market price reduction-driven savings), whereas the Joint Utilities analyzed Total System Costs (direct RPS premium costs and costs to other producers less forecast wholesale market price reduction-driven

[16] The participating utilities were Central Hudson, NYSEG, RG&E, and Niagara Mohawk.

[17] Staff's modeling specified both retirements and generation addition extrinsic to the model, whereas IPM employs internal logic to retire or add generation based on meeting reliability criteria and economic sufficiency criteria.

savings).[18] Staff limited its quantitative analyses to the period ending 2013, despite recognizing that the proposal would impose costs on electric ratepayers thereafter. The Joint Utilities carried their quantitative analyses out to 2020, and reported results through 2013 with the explicit caveat they were only for the purpose of comparison to Staff's limited time period.[19]

A technical meeting concerning the two studies (and a different type of study submitted by RETEC) was held on August 13, 2003, followed by parties' comments. Sometime during or after this time period apparently (*see* Attachment A), a decision was taken to revise the Staff studies, adopt the Staff cost methodolgy, and include the revised studies in the DGEIS that the Commission had previously directed be completed. The new studies ("CSII") followed essentially the same analytical approach as the initial Staff Cost Study. It used the identical Supply Curve, load and other forecasts from the SEP2002 (other than adding a new fuel forecast, to reflect higher gas prices than previously assumed). Several input assumptions were changed, however, including the required RPS "incremental" targets (from a 2013 total of 8% in the initial study to 4.66% in CSII), and the treatment of assumed generating plant additions and retirements.[20] In addition, in Volume B of CSII, a number of "alternatives" were studied.

A revised version of CSII appears in the RD ("SC-RD"). As described in the RD (p. 105), the SC-RD adopts some of the parties' criticisms of CSII (a listing of changes from CSII appears

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18 Accordingly, both studies forecast the direct RPS premium costs as intermediate results.

19 Joint Utilities' letter of July 28, 2003 to the ALJ (pp. 2-3 & n. 3 and associated text). The almost three-fold increase in direct RPS costs between the period ending 2013 and that ending 2020 found in the Joint Utilities' Study (July 28 letter. p. 3), and the implication that the Staff forecasts would have similar post-2013 cost impacts from the direct RPS premiums, has seemingly not been recognized in the deliberations leading to the RD.

20 A significant difference between the ICF model and the DPS studies, and a significant defect of the DPS modeling in the view of the Joint Utilities, is that DPS was required by its decision to use GE MAPS to make fixed input assumptions for plant addition and retirements in its studies. In contrast, the IPM includes components that determine plant retirements and additions internally, based on "need" (*i.e.*, reliability criteria) and adequacy of market revenues forecast in the model. Although this defect had been identified previously by the Joint Utilities (Attachment B, pp. 52-53), it is not adverted to in the RD and therefore apparently not considered in the RD.

on pages 42-43 and 48 of the RD). The RD (p. 105) then dismisses the remaining "critiques and corrections" on the basis that the SC-RD "cost estimates are sufficient to advise the Commission on policy choices given the long-term uncertainties inherent in such forecasting[.]" CS-RD does not include the alternatives addressed in Volume B of CSII. Instead, the RD (pp.13-14) defines three generalized "Options" (A, B and C) and recommends Option C. The spreadsheets referred to in Appendix B and set forth on the Commission's website reveal the following characteristics for these Options (values presented for costs are based on "current" (*i.e.*, updated, higher) fuel forecasts, not the SEP2002 fuel price forecasts):

	Option A	Option B	Option C
Cumulative MWH of Renewables (000,000)	8.4	14.5	14.9
NPV of Net Bill Impacts (Million$)	$147	$442	$158
Ratio of Cost to cumulative Renewables ($/MM MWH)	17.50	30.41	10.57

As discussed hereafter, the Joint Utilities except to the treatment of cost studies adopted in the RD.[21]

B. The RD Lacks a Rational Basis for its Determination of Costs

While presenting the results noted above, the RD is noteworthy for the absence of any reasoned discussion and decision-making regarding RPS program cost studies. Even though the RD (pp. 93-105) contains a twelve-page summary of portions of the cost study comments offered by various parties, the RD contains no analysis of those comments. It does not identify which of

[21] We note that the RD does not disclose how the SC-RD studies were done, and no supporting input information has been provided to the parties. Thus, the Joint Utilities, individually and collectively, each reserve the right to take further exceptions at such time as we are provided with sufficient information.

the comments were accepted (and why), and which were rejected (and why). Appendix B to the RD merely states that the nominal cumulative direct RPS premium costs for the RD-recommended program is over $1.1 Billion and reports the Net Present Value ("NPV") for the net bill impacts. The Joint Utilities continue to believe that state-sponsored programs that are forecast to cost New York's citizens over $1.1 Billion in direct, out-of-pocket costs require comprehensive and integrated evaluations and explanations that have not yet been fully performed in this proceeding concerning the calculations of the costs of the Options considered and the program recommended in the RD. It is also imperative that the Commission fully examine the cost effects before it finalizes the RPS parameters.

Nor, as discussed in Section V (E) hereafter, is there any analysis purporting to support the RD's conclusion that the SC-RD in fact is "sufficient" for the Commission's further consideration. No criteria for evaluating "sufficiency" are identified in the RD. The entirely unsupported nature of the RD's conclusions thus means that the RD does not meet the State Environmental Quality Review Act ("SEQRA") requirement that decision-making entail a "hard look" at the facts, and a "reasoned elaboration" of the basis for the conclusions reached. *Matter of Jackson v. New York State Urban Development Corp.*, 67 N.Y. 2d 400, 503 N.Y.S. 2d 298, 494 N.E. 2d 429 (1986).

The reliability of the Staff modeling approach has been repeatedly questioned. A basic concern is that the resources "reached" in Staff's analyses are comprised largely of intermittent wind power facilities located in the western part of the State. These facilities have power production characteristics almost perfectly out of synch with the needs of the New York electrical system, in that they produce most of their power at night whereas the peak system needs occur during the day.[22] Moreover, they are forecast by Staff's Supply Curve to be located west of the

[22] This problem could be exacerbated if Staff's proposal for CFDs were approved as an acceptable contracting mechanism (*see* Section II (B) above).

Central East Total East constraint, where prices are lower than to the east. While one would expect that operation of those facilities would tend to drive down the LBMP in that area, off-peak LBMPs tend to be relatively lower anyway. Thus, the prospect for major wholesale price reductions seems qualitatively limited. Yet Staff's modeling predicts reductions almost equaling the direct RPS premium costs based upon installed wind capacity and 40% imported energy. Conversely, if the forecast renewables do produce sufficient energy to drive down the wholesale energy prices to the extent forecast by Staff, how will it be feasible for existing generators to remain economically viable (and avoid additional non-economic subsidy payments — not included in Staff's cost studies — to keep generators needed for reliability available)? No affirmative demonstration of the reliability and no independent corroboration for the results of the Staff modeling have ever been presented.[23]

When the Joint Utilities modeled an 8% RPS program target in their initial study using IPM, they found that the reductions in wholesale power prices produced in IPM were "relatively small,"[24] nearly 3% of about $5 Billion in 2013 Annual System Production Costs,[25] or something less than $150 Million in 2013. In contrast, Staff's modeling of the 8% incremental RPS target produced wholesale cost savings of $231 Million in 2013, more than 50% greater, and almost entirely offsetting the $247 Million in direct RPS costs forecast by Staff for 2013. Given that both initial modeling efforts largely employed SEP2002 assumptions for the major reference case drivers, one would anticipate similar magnitudes for the forecast wholesale cost savings.[26]

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23 Such independent corroboration should be undertaken as part of the analysis of the Phase 2 Reliability Report.

24 July 28, 2003 letter, p. 3.

25 July 23, 2003 ICF PowerPoint presentation: "Report of Initial Analysis of Proposed New York RPS," pp. 32 & 35.

26 The initial modeling efforts of both Staff and the Joint Utilities employed the SEP2002 gas price forecasts. Staff's more recent modeling (in CSII) and the SC-RD employed a revised gas price forecast which has the

Another indication of the lack of reliability in the Staff modeling is shown by comparison of results from CSII to those summarized for the SC-RD. CSII was addressed to production of 11,675,660 MWH in 2013 and the NPV (cost based approach) of the net program costs were reported as $58,689,463 (2003$). SC-RD is addressed to production of 13,706,906 MWH in 2013 and the NPV (cost based approach) of the net program costs is reported as $158,019,463 (2003$). Both sets of values relate to the new fuel forecast. The 170% increase in NPV costs in relation to the 17% increase in RPS targets calls the SC-RD further into question by showing just how sensitive the quantitative results are to the input parameter specifications and how the calculated value swings significantly in response to a relatively limited number of changes in inputs.[27]

The RD also fails to explain why the Option B cost analysis of the acquisition of 14.5 million MWH by 2013 costs an average of $30.41/million MWH as compared with the Option C ratio of $10.57/million MWH. In addition, one would expect that the option with the lowest amount of renewables (Option A) would have both the lowest cost for the direct RPS premium costs (because the renewables are supposedly "reached" along a hypothetical economic supply curve and the lowest cost ones reached first), and the greatest energy price reductions per unit of renewables (because of the marginal nature of the wholesale price reductions). The Staff costing method, however, inexplicably produces the counter-intuitive result (comparing Option C to Option A) that twice the amount of renewables is reached at two-thirds of the average unit cost/million MWH. This anomaly is neither acknowledged nor explained in the RD.

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effect of increasing forecast wholesale prices, increasing the magnitude of the forecast wholesale cost savings from an RPS, and also increasing the sensitivity of the outcome to errors in Staff's methodology.

27 Similar non-linear relationships appear to exist in the emissions reductions forecast in the CSII studies as compared to the SC-RD studies. In this case, the 17% change in "targets" has produced a far greater forecast reductions in emissions.

The Joint Utilities have previously noted that the Staff modeling approach requires specification of a great number of inputs and that all inputs must be very accurately specified to avoid errors. We suspect that inconsistencies or outright errors have led to the disproportionate results reported in the RD. The previous reviews of the initial Staff cost study and of CSII disclosed numerous errors in inputs and modeling representations. These have been explained by several parties. The RD (p. 94) inappropriately criticizes the parties for not providing quantification of their objections to the Staff modeling of CSII, but there was no procedural opportunity for doing so. Moreover, there was no reason to commit resources toward quantifying objections to the initial Staff Cost Studies because it was known that Staff was making changes to its initial studies (and the requests by the Joint Utilities and other parties to be informed about the proposed changes were rejected).[28] Once CSII was issued, the procedural schedule was so rushed that there was no opportunity for responsive submissions, no opportunity to both prepare for the on the record evaluation of CSII and quantify a party’s objections to it, and, moreover, the decision to employ the Staff approach exclusively had already been implicitly taken. Furthermore, quantifying the objections could realistically only be done by Staff, which had the data base and free and unrestricted access to its models and input data sets, as well as intense knowledge that outside parties (particularly those without MAPS licenses) do not have of how it had done its own modeling.

C. Impact of the RD's Acceptance of Staff's Costing Approach

It is unjustified for Staff's modeling approach to have been accepted and relied upon uncritically (no analysis is reported in the RD) in the face of the unquestionable reliability of IPM.

[28] Moreover, Staff developed a quantification of the differences between the Joint Utilities' initial study and Staff's initial study.

The un-analyzed and apparently uncritical acceptance of the Staff modeling led to related errors in the RD.

For example, the RD fails to recognize that the updates to the fuel forecasts it adopted (pp. 22, 42 & n. 59) required the development of a new Supply Curve, based consistently on the same fuel forecasts. The RD's failure to recognize the interrelationship between higher market revenues, from higher fuel prices, and RPS premiums, leads the RD (p. 75) to conclude incorrectly that: "The current and projected cost of electricity from renewable resources will remain at costs above the market cost of conventional generation through the time period studied." In fact, the Joint Utilities' analysis of CSII had disclosed that resources "reached" in the original Supply Curve did not require an RPS premium under the assumption of higher fuel prices. The very definition of the supply curve as presented by Mr. Grace in July 2003 is "based on the Renewable Generation Premium (RGP), the required premiums over commodity market value for each renewable generator to bring it on-line" (p. 6). This means that the updates to fuel forecasts and the consequent increases in wholesale prices would produce greater wholesale revenues and a lower generator "requirement" for RGP, all else being equal. Therefore, the RD should have caused a new supply curve to be prepared, corresponding to its adoption of the "updated" or "current" fuel forecasts. The failure to update the supply curve consistent with the adopted higher fuel cost forecast also has the effect of overstating the marginal reductions in wholesale energy prices resulting from an RPS.

The lack of appreciation in the RD for this interrelationship also influences other recommendations, including the plainly incorrect assertion (p. 23) that an "RPS is necessary, in fact, to promote the development of additional renewable resources for New York's retail energy portfolio." In reality, many of the resource types assumed to require an RPS premium in the original Supply Curve do not "need" a premium due to the higher wholesale market revenues that will result from the fuel prices adopted in the RD.[29]

Finally, the RD makes inconsistent determinations between its cost estimates and its contracting requirements. The RD cost estimates end at 2013. The RD contract requirements do not. The RD (p. 23) seemingly requires eight-year contracts in 2013 (but fails to count the seven years of post-2013 costs of those contracts, the six remaining years of the 2012 contracts, *etc*. in the RD's cost study). This inconsistency, although identified more than once by the Joint Utilities previously, is incorrectly perpetuated in the RD.

D. The RD Fails to Apply Any Meaningful Scrutiny to the Adopted Staff Cost Study

In their Supplemental Cost Study Comments (Attachment D), the Joint Utilities set forth at length the major flaws and deficiencies in the Staff Cost Study, which the RD (pp. 21-22) has apparently determined to be sound. The Joint Utilities discussed in their Supplemental Comments the extent to which the Staff Cost Study had failed to analyze fundamental factors impacting the cost of an RPS program, and had used very favorable assumptions in connection with the factors that were analyzed. Specifically, the Joint Utilities discussed the Staff Cost Study's failure to address (1) post-2013 costs, (2) transmission- and market-related costs, (3) impacts associated with displaced and retired generation, (4) reliability costs, and (5) the higher costs associated with any ACM. The Joint Utilities also discussed the cost-suppressive impacts associated with key assumptions used by Staff in the Cost Study. Assumptions regarding (1) the levels of imports, (2) wind parameters, (3) RPS resource levels, (4) wholesale electricity prices, (5) CFDs, (6) the

[29] This misunderstanding seems also to have led to incorrect conclusions concerning (i) the adoption of the misnamed "hybrid" Staff model, and (ii) the concomitant rejection of the Central Procurement Model and the pilot program recommended by the Joint Utilities.

production tax credit, (7) fuel costs, (8) unforced capacity ("UCAP") payments, and (9) emissions combined to create an inaccurate assessment of RPS program costs. Because the Staff Cost Study failed to adequately predict the ultimate real costs and benefits of an RPS program in New York State, the Joint Utilities had recommended that further cost examination continue. We also had recommended that consideration be given to a near-term implementation of a pilot program. The Joint Utilities expressed the view that a properly designed pilot program could greatly inform the record on both reliability and cost issues.

While the RD (p. 21) thus estimates the total, net present value of RPS program costs at $158 Million to $328 Million, for the 2006-2013 period only, the Joint Utilities estimated that the net present value of ACM-related costs alone during the same time period (based on the conservative assumption of an annual 25% shortfall in reaching each year's milestone) could reach $371 Million. Further, as discussed in Section VI (A) hereafter, the RD is silent as to whether the recommended RPS milestone levels (pp. 16, 54, App. B, Tables 1 & 2) are "fixed." If they are not "fixed," RPS program costs could increase enormously in any given year. In the event the Staff's Cost Study forecast of 40% RPS imports fails to materialize — a highly probable outcome — the NPV of RPS program costs by 2013, according to the Staff Cost Study, would exceed $1.2 Billion to $3.4 Billion, depending on the assumptions. The ICF Cost Study, which modeled different assumptions and examined costs out to 2020, predicted a net present cost of between $2 Billion and $6 Billion. If the RPS Program costs indeed are orders of magnitude greater than those set forth in the RD, then the associated bill impacts will be orders of magnitude greater.

Finally, the RD (p. 43 n. 60) comments that its recommended decrease to the baseline, and concomitant increase in the required RPS milestone levels, would result in no increased costs over and above those forecasted in the Staff Cost Study. No party has been given an opportunity to examine the supporting analysis for such a comment.

E. Requisite Additional Cost Analyses

According to the RD (p. 29), "[t]he Commission has an ample record to decide fundamental RPS design policies." The Joint Utilities disagree. The RD gives little or no indication that the compiled record was subjected to the requisite “hard look” in reaching the RD’s determinations. This conclusion is also incorrect with respect to major issues. For example, the DGEIS studies showed that other alternatives to the “prime case” presented lower costs in relation to the forecast RPS targets than the “prime case,”[30] yet those alternatives do not appear to have been considered deeply if at all in the RD. The RD reports results for Option A that are not consistent with the results of the alternatives studied in CSII, when viewed in relation to the "prime" or "recommended" alternative. Likewise, the RD gives little indication that it compared its recommendation to the other alternatives listed in the DGEIS. Had it done so, some of those alternatives would have been shown to be more desirable from a cost/benefit standpoint than the recommendation of the RD.

The disparity of the Staff and Joint Utilities' cost estimates is clearly dependent upon the assumptions, including time periods, underlying the cost studies submitted by those two parties. Indeed, the RD recognizes that the cumulative impact of RPS premium payments will "reach between $1.14 and $1.35 billion by 2013, *depending upon the pricing approach chosen*" (p. 21) (emphasis added). Moreover, the RD (p. 30) acknowledges that, "without further guidance on these issues [RPS program initiation and design], further studies in the abstract will be of academic value only."

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30 *See* Joint Utilities’ Supplemental Cost Study Comments, Attachment D, pp. 6-7.

In its discussion of costs and benefits (p. 21) the RD focuses entirely on the Staff Cost Study, and modifies that study to support adoption of the recommendations set forth in the RD. As discussed in this Section V, the different assumptions underlying the Staff and Joint Utilities' cost studies are critical in assessing the validity of each of the models proffered by those two parties.

The RD is based on the premise that the Staff Cost Study is the appropriate starting point for cost analyses. This premise accords undue and unexplained deference to the Staff model and its cost impacts. During the course of the proceeding, the ALJ failed to disclose to the parties that the Staff analysis would be the sole basis for the RD. Moreover, the conclusory statement at page 105 of the RD that "[m]any of the parties' comments have been taken into account in revisions for the Recommended Decision" simply cannot substitute for a reasoned analysis of the benefits and flaws of each model and a justification for the specific recommendations reached. Further, by limiting its discussion of costs to Staff's modeling approach (albeit with some modification to reflect other parties' concerns), the RD effectively forecloses the Commission from deliberating the pros and cons of adopting any alternative approach.

In many instances, the RD does not recommend a specific course of action, but instead outlines the design options available to the Commission. Thus, there is no certainty about the design of the RPS until the Commission renders its RPS Policy Statement. Only when that design is known can parties (including Staff) conduct cost analyses that are more than mere "academic exercises." Further, as discussed in Section III (B) above, the results of the Phase 2 Reliability Report, which are not expected to be available until this Fall, could have a significant impact on the design of the RPS and, therefore, on RPS costs. After the Commission issues an RPS Policy Statement setting forth the design parameters of the RPS (recognizing the results of, among other things, the reliability Phase 2 Report[31]), further cost analyses will be required. Only after such parameters have been determined will it be possible to conduct realistic analyses of the actual financial effect that the RPS will have on customers and the LSEs. These analyses can be conducted immediately upon the identification by the Commission of the key elements of the regulatory model it is considering adopting.

VI. OTHER MISCELLANEOUS RPS DESIGN ISSUES

A. The RD Errs in Not Specifying that Baseline and Milestones for Each Year Must Be Fixed Numbers

As explained in the Joint Utilities' Initial Comments (Attachment B, pp. 25-26), establishing an accurate baseline is a critical component of the design of the RPS. If the baseline is underestimated, thus increasing the increment necessary to meet the target objective, New York consumers may ultimately pay too much. If the baseline is overestimated, insufficient new renewable generation may not become available, thus jeopardizing the State's goal in implementing an RPS.

According to the RD (p. 15), "[t]he baseline, targets and milestones reflected in the Cost Study II, Prime Case, as modified in Appendix B . . . are recommended." While relying on Staff's baseline, the RD indicates that various additions and modifications are made to Staff's 28,896,189 MWh baseline. The Joint Utilities generally concur with the baseline recommended for adoption in the RD (except to the extent discussed in Section VI (H) hereafter in connection with small hydroelectric projects). What is most critical to the Joint Utilities is that the incremental

[31] While the RD (p. 86) notes that the Commission will have the benefit of the Phase 2 Report in time for *implementation*, that information is critical for purposes of establishing the parameters of the RPS design. Contrary to the RD's implication, it is unsatisfactory to relegate consideration of reliability issues to the to-be-instituted implementation proceeding.

percentages for each year shown on Table 2 of Appendix B remain fixed through 2013[32] and not be reopened as part of the 2008 review or any other review.

Once the milestone figures for each year are established, there is no need to revisit those numbers. Rather, the focus should be on which eligible RPS resources supporting attainment of incremental RPS targets should receive premiums and which should not. If the milestones for each year can be modified anytime in the future, the required incremental amount of renewables becomes an unacceptable moving target. Depending upon which RPS design model is adopted, such a moving target creates an additional potential imprudence exposure to which the utilities would be subject and an additional cost exposure to all LSEs.

The RD clearly contemplates the potential addition of certain renewable technologies as available resources to the RPS program.[33] In discussing the eligibility of hydropower, the RD also discusses a monitoring process of continuing resource availability.[34] The Commission should make clear that what is contemplated by the potential addition of resources and the monitoring process will not involve any adjustment to the baseline.

The Joint Utilities do not object to the potential inclusion of certain renewable technologies that could qualify for a premium at some future point in the RPS program, as discussed throughout the RD.[35] However, for the reasons discussed above, the Joint Utilities reiterate that the addition

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32 The Joint Utilities contemplate one limited instance in which it might be appropriate to modify the milestone targets: if the Commission determines that any one year's incremental percentage cannot be met and delays some of the milestone amounts to future years.

33 RD, p. 17 ("On balance, the recommendation is to commence the RPS including specified resources and to develop procedures for inclusion of additional resources as they develop or improve."). *See also*, RD p. 20 ("[T]he recommendation is to continue refining criteria, to provide a mechanism for new technologies to apply, and to consider the complementary role of future demand side management initiatives to reduce overall load, thereby increasing the proportion of renewables.") and p. 60 ("The Commission should establish a mechanism, in the implementation phase of this proceeding, to add resources to the eligibility list.").

34 RD, p. 50 ("[T]he recommendation is that the monitoring process continue to oversee the status of renewable resources currently counted in the baseline, to ensure that they will remain available as the program progresses.").

35 *See* n. 33, *supra*.

of these technologies must not alter the milestone figures for each year set forth in Table 1 of Appendix B of the RD, and that those incremental percentage levels must remain fixed over the life of the RPS program.

B. The RD Errs in Not Recommending Fixed LSE RPS Targets

As more fully discussed in Section VI (E) hereafter, the RD inappropriately excludes NYPA, municipals or municipal public power entities and "very small" ESCOs from the requirements of the RPS program. The RPS requirements should apply to all New York State LSEs, or at a minimum, to their customers through a charge imposed on those customers' bills (which obviates any concerns over whether the Commission has jurisdiction over NYPA or municipalities).

It is critical, however, that should certain LSEs be excluded, over the objection of the Joint Utilities and likely other parties, the target percentages should not be revised from those shown on Tables 1 and 2 of Appendix B. Otherwise, non-excluded LSEs will be held to improperly-inflated percentage targets. The RD recommends the exclusion of NYPA, municipals and very small ESCOs from the RPS, and notes that parties agreed, that if entities such as LIPA and NYPA will not partake in the RPS program, their full service load requirements also should be removed from the target calculations. Table 22 appears to reflect the effect on the incremental targets of the non-excluded LSEs if NYPA, municipals and very small ESCOs are exempt from RPS compliance, without excluding from the SEP2002 forecast the MWH attributable to the excluded LSEs that are reflected in that forecast. Mathematically, this mismatch results in increasing the incremental percentage for the non-excluded LSEs. Because of this skewing effect, the Joint Utilities urge the Commission to accord no weight to Table 22, and to rely exclusively on the incremental percentage levels identified on Tables 1 and 2.

Consistent with the Joint Utilities' position as enunciated above, Tables 1 and 2 of Appendix B would be utilized in the following manner. For each year, all non-excluded LSEs[36] should be responsible for funding renewables equal to the target percentage times the amount of that LSE's load. To the extent that the SEP Forecast differs from the sum of the actual loads of the non-excluded LSEs, the total level of renewables may differ from the amounts shown on Table 2. Contrary to the RD's recommendation (p. 70), added costs associated with the exclusion of LSEs should not be passed along to the remaining LSEs, nor, in the case of NYPA customers who receive retail service from a non-exempt LSE, should the remaining customer base of the non-exempt LSE be burdened with the costs that otherwise would be borne by NYPA customers. The percentage increments should only apply to that portion of the the LSE customer base that will fund the RPS program, and not to the entire LSE customer base.

C. The RD Does Not Clarify Whether the Object of RPS Compliance Should Be the Acquisition of Certificates, Energy, or Both

The RD is noteworthy for its ambiguity regarding the ultimate objective of RPS compliance under either a Central Procurement Model, an Individual Compliance Model, or the hybrid model: will compliant entities be purchasing certificates only, energy only, or both? In fact, the RD (p. 23) goes so far as to say that "load-serving entities should . . . be free to opt to procure. . . load or certificates."

The RPS should be a certificates-only program. Managing an RPS system in which the central procurement State agency or LSEs have the ability to meet their target commitment with either or both energy or attributes will make it much harder to determine whether the output of one

[36] As noted in Section VI (E) hereafter, the Joint Utilities oppose excluding any LSEs from the RPS program.

renewable facility has been double-counted for RPS, environmental disclosure, and other purposes. This will complicate rules development for the RPS generally and the tracking and trading system and environmental disclosure mechanism in particular. Finally, if this ambiguity is retained in the RPS Policy Statement, the implementation proceeding may be delayed as related issues emerge and time is taken to resolve them.

As noted in our Reply Comments (Attachment C, pp. 38-40), the Joint Utilities agree with NYSERDA, NYISO, and LIPA that energy should be unbundled from certificates. RPS-eligible resources should compete with other generators in the existing NYISO-managed markets and compete among themselves in a separate certificates market.[37] In this way, RPS eligible resources will take the same market risk as other generators, and RPS premium costs and interference with wholesale energy and capacity markets can be minimized.

D. The RD Errs in Recommending a Deliverability Requirement[38]

The Joint Utilities take exception to the RD's treatment of the deliverability issue (*i.e.*, whether the renewable energy must be delivered into the New York control area for the attributes or credits associated with that energy can be traded in New York State and count toward the RPS targets) in this proceeding because there are errors of fact in the RD's rationale in support of this requirement. As the RD (p. 77) points out, the parties did not reach consensus on this critical issue.

The RD (p. 82) correctly concludes that "(u)nbundling the renewable attributes from the electric energy and establishing an attributes market is a fundamental aspect of the RPS design." The RD (pp. 85-86), however, adopts the incorrect position that the Commission should impose a

[37] Under the Individual Compliance Model and the RD hybrid model, LSEs would also participate in the secondary certificates market.

[38] Central Hudson does not join in Section VI (D).

deliverability requirement for the New York RPS. The RD's justifications for adoption of this recommendation are flawed.

First, the RD (p. 85) claims that the delivery requirement will result in lower wholesale prices. Even if the delivery requirement will result in lower wholesale prices, it is not clear from the record if any such reduction in prices would be sufficient to offset the probable increase in the price of renewable energy credits that may arise as a result of a delivery requirement. Therefore, the overall cost of the RPS program may increase as a result of a delivery requirement even if wholesale prices are lower. Second, the RD (pp. 83-84, 86) erroneously uses the example of the Massachusetts RPS and the ISO-New England control area requirements as justification for imposing a deliverability requirement in New York State. The delivery requirements in ISO-New England actually support the arguments against a deliverability requirement. The requirement in Massachusetts that energy must be used in the ISO-New England control area is not the same as a requirement that it be delivered into a single state, such as Massachusetts. ISO-New England is a regional control area encompassing six states, while the NYISO administers a single state control area. Indeed, the RD (p. 24) acknowledges regional trading in renewable credits exist.

Finally, the RD's deliverability requirement recommendation contradicts the RD's recommendation (p. 76) that "New York should move ahead and design a New York trading system compatible with neighboring systems, the latter of which the Joint Utilities support." If New York develops a trading system compatible with neighboring systems and those systems (*e.g.* PJM and ISO-New England) have an RPS system that allows for tracking the production of certificates or credits in that region and verification of delivery of those credits to an entity in New York State, then deliverability of energy into New York State will not be necessary with a region that has reciprocity.

Therefore, the Joint Utilities support the recommended option found on page 86 of the RD: “In the alternative, the Commission could decide on a program geared toward meeting these goals on a regional, rather than state-specific, basis.”

E. The RD's Exclusion of NYPA, Municipals/Municipal Public Power Entities, and "Very Small" ESCOs Lacks a Rational Basis in the Record

The RD (pp. 69-71, App. C, para. 4) recommends that certain LSEs should be excluded from RPS compliance obligations. The affected LSEs would include all entities except (i) NYPA (because costs should not be added to a "priority program" for economic development and NYPA's energy portfolio is already baselined renewable resources); (ii) either "municipal public power entities" (because their energy portfolio already consists largely of renewable hydropower, they practice "aggressive" energy efficiency and conservation, and have a slight "incremental load"), or "municipals" (it is unclear to what this term refers); and (iii) "very small" ESCOs.

The Joint Utilities takes strong exception to the suggestion that economic development and demand response/demand management concerns are the exclusive province of LSEs other than the Joint Utilities. As discussed hereafter, we are as deeply concerned about RPS program costs on our customers as any other LSE participating in this proceeding. Also, it is irrelevant that a large portion of the energy procured by NYPA and municipal customers may consist of low-priced, base-lined hydroelectric resources. What should "matter" in this proceeding are the costs associated with achievement of incremental RPS targets, which should be borne by each cost-causing entity, and not shifted to the Joint Utilities' customers or to other non-exempt LSEs. In other words, if the RPS is going to benefit everyone in New York State, then everyone in New York State should fund it. The rationale for the exclusion of those already favored with the lowest cost resources from sharing in paying for common good costs of higher cost resources is unclear.

The RD's implicit conclusion that those paying the most should pay still more, while those already paying the least should thereby pay relatively still less, is of questionable soundness.

The RD fails to define what is a "very small" ESCO. An ESCO that could be "very large" in one utility's service territory could be "very small" in another utility's service territory. At some point a "very small" ESCO can become a large ESCO. This could provide gaming opportunities where large ESCOs create numerous "very small" affiliates in order to avoid the RPS premium obligation. Moreover, the Commission has expressly noted in Opinion No. 98-19 (p. 19)[39] that there must be equal treatment of ESCOs and T&D utilities in this area.

The matter of defining a “very small” ESCO – and of managing the transition as ESCOs move from no responsibility for RPS costs to assuming a responsibility for RPS costs – has clear competitive implications, ESCO-on-ESCO. These implications should be considered both in this proceeding and in Case 00-M-0504. Moreover, there is no justification for exempting any ESCOs from the RPS. One of the great benefits of central procurement is its ability to equalize the positions of all LSEs, from the smallest to the largest.

At the very least, as stated in Section VI (B), the Joint Utilities' customers should not be required to absorb RPS program costs that should be assigned to any exempt LSEs. The customers of the Joint Utilities should be required to absorb only the RPS program costs associated with the Joint Utilities' customer load.

F. The RD Errs in Determining Which Resources Should Qualify as RPS Resources and Which Resources Should Qualify for RPS Premiums

[39] Case 94-E-0952, In the Matter of Competitive Opportunities Regarding Electric Service, filed in Case 93-M-0229, *Opinion and Order Adopting Environmental Disclosure Requirements and Establishing a Tracking Mechanism*, Opinion No. 98-19 (issued and effective December 15, 1998).

The RD properly distinguishes RPS-eligible resources from RPS-premium eligible resources: RPS premiums should be streamed only to RPS eligible resources who truly require them and whose commercial success is important to achievement of incremental RPS targets. Thus, under the RD (App. C, para. 14), green marketing and SBC-program funded projects, and resources developed prior to January 2003 would generally be "counted" toward achievement of the 25% RPS program target but would not receive RPS premiums.

The RD (p. 23), as corrected in the *Erratum Notice*, however, would award RPS premiums to small hydroelectric resources, irrespective of how long they have enjoyed commercial operation. No rational basis exists in the record for the distinction drawn between these resources and the green marketing and SBC-funded projects. In order to minimize RPS program costs, no RPS premiums should be provided to projects that have already demonstrated commercial success. There is simply no sound policy reason for the award of RPS premiums or other subsidies to projects that do not require them. Small hydroelectric projects should be included in the baseline and the milestone targets should be adjusted accordingly.

In addition, the RD (p. 20) is ambiguous on the issue of whether high-impact hydropower projects (run-of-river greater than 30 MWs per facility or new impoundments) should be excluded from consideration as an RPS resource, or just from RPS premium eligibility. The Joint Utilities believe it irrational to conclude that a hydroelectric resource should not be deemed to be renewable for purposes of RPS or RPS premium eligibility. Given the stringent environmental standards applicable to any hydroelectric resource, it makes little sense to carve out any such facility as "high impact." At a minimum, these resources should be deemed RPS resources that can count toward the 25% target.

G. The RD Errs in Recommending the Establishment of Tiers

The RD (pp. 20-21, 67) recommends the creation of at least two tiers of RPS-premium eligible resources: (i) a main tier and (ii) a 2% SBC-like tier (solar, small wind up to 300 kW and fuel cells) that would be eligible for other existing program funding, because of their "potential value" in being located near heavy load areas. Less clear is whether the RD (pp. 20-21) also recommends the creation of a third "maintenance" tier for small hydropower projects (< 10 MW) that would otherwise be retired due to expiring "above-market priced" contracts.

The RD provides no justification for the creation of any tiers, nor for the selection of a 2% SBC-like tier over a 1% tier, as endorsed by Staff and other parties. No RPS-eligible resource should be singled out for special consideration from other RPS-eligible resources. All are important toward achievement of the RPS target, and for purposes of such achievement, the "flavor" of the RPS resource should not matter. Such artificial discrimination between technologies could lead to certain resources receiving more of a premium than economically appropriate, and ultimately result in the deployment of technologies that simply are not "ripe" for commercial exploitation over the deployment of other, more cost-effective RPS technologies.

To the extent the RD expresses the belief that an SBC-like tier is necessary to support the siting of RPS resources in heavy load areas, such as downstate, this belief is misplaced. Energy and capacity market pricing alone, not to mention the subsidies provided by existing SBC programs, already encourage investment in downstate facilities. An additional RPS premium "investment" of $150 Million (RD Appendix B, Tables 7 & 8) should not be made.

At a minimum, the Commission should limit eligibility for the 2% tier technologies to behind-the-meter resources only. Fuel cells or other otherwise eligible technologies that exist and function as merchant generators should count toward achievement of the RPS target, but should not be eligible for the same premiums as the 2% tier technologies.

If the RD is also proposing the creation of a maintenance tier, "above market" must be defined. Moreover, do small hydroelectric facilities with contracts that happen to be above market now, but not when their contracts were signed, qualify? Also, as discussed above there is no economic reason for the payment of subsidies to existing facilities. The payment stream afforded by LBMP pricing and sales of capacity — particularly since many facilities would be "price takers" and thus likely to receive greater revenues than warranted on a strict cost basis — are more than sufficient to assure continued plant operations. Such resources should be included in the baseline, and the milestone targets adjusted accordingly. The Joint Utilities would also point out that the record is purely speculative on what actions these projects would take upon expiration of existing power purchase agreements. For all we know, they would enter into other bilateral arrangements — but for the enticement of RPS premium payments. Finally, most, if not all, of these "above market" contracts were entered into with the belief that, in exchange for receiving above-market priced contracts for financing, customers would receive long term benefits after the contracts ended because the facilities would then supply New York State with low-cost energy. At a time when customers would stand to benefit from this low-cost energy, the Commission should not be considering allowing continuation of above-market, and perhaps unnecessary, premiums.

H. The RD Errs in Not Categorically Recommending Rejection of RPS Premiums for RPS Resources Receiving Other Subsidies

The RD (pp. 70-71) would exclude municipal solid waste facilities in part because they have "a source of funding in addition to electric sales." Subject to our discussion hereafter regarding the federal Production Tax Credit ("PTC"), the RD otherwise appears to sanction the award of RPS premiums to resources that are already the recipients of state and/or federal subsidies. As noted above in Section VI (G), the RD expressly advocates additional RPS premiums for resources already funded through existing SBC programs.

From a cost perspective, the Joint Utilities strongly object to the provision of RPS program subsidies to projects already receiving state or federal subsidies. As we have discussed in our Reply Comments (Attachment C, p. 14 & n. 34), New York State alone currently provides at least 12 incentives for renewable projects. The Commission needs to decide that New York State consumers should not be required to underwrite yet another subsidy for recipients of these and other incentives. To the extent the RD does not clearly recommend adoption of such an exclusion from RPS premium eligibility, the RD is in error.

Finally, the RD (p. 22, n. 31) includes an ambiguous recommendation regarding the eligibility of projects that may be eligible for a renewed PTC: "To ensure the success of the New York RPS before passage of the [PTC], the recommendation is to institute the program so as to provide that incentive, until the [PTC] is reauthorized. . . ." To the extent the RD recommends that RPS premiums should not be awarded to projects once they receive the renewed PTC, we agree, for the reasons discussed above. However, to the extent the RD recommends that an RPS premium should continue alongside the PTC, we disagree, for the reasons discussed above.

I. The RD Fails to Consider All Tasks Left for the Implementation Process, the Issues Necessary for a 2006 RPS Start Date, and the Proposed 2008 Review

The RD, in Appendix D, "Implementation," recommends "first, to initiate a new proceeding for the implementation process." Appendix D references only the issues of expanding eligibility for new or improved technologies, analysis of the Phase 2 Reliability Report, and consideration of the Attributes Trading program. In order to make a new proceeding on Implementation valuable, the Commission should also include numerous other tasks that need to be addressed. These tasks may include, but are not limited to, the issues of (1) rules for the SBC-like tier, (2) rules for existing small hydropower projects, (3) rules for a certificates tracking and trading system, (4) how to handle the current conversion transaction system, (5) treatment of imports and exports, (6) determination of a banking and borrowing system with true-up rules, and (7) settlement rules.

The RD (p. 24) recommends that "the program compliance provisions commence with the calendar year 2006." In order to realize a 2006 start, the Joint Utilities recognize that considerable additional work needs to be done. We therefore request that the Commission immediately reconvene the parties to address the various issues. The Joint Utilities, in their Supplemental Cost Study Comments (Appendix D, p. 36), had proposed the implementation of an RPS pilot program for the first year of the RPS, 2006. Such an approach, utilizing central procurement and some portion or all of the 2006 incremental percentage, would help the parties more fully explore the workings of the RPS and give ample time for the necessary Implementation Process to develop, while helping to achieve the 2006 target. This could be followed by a 2007 review of the RPS, with the lessons learned applied to the RPS.

The RD (p. 49) recommends an evaluation in 2008 as the first milestone date, "to evaluate the costs and benefits, invite more generation resources to participate, adjust incentives for incremental renewable acquisition or otherwise modify the RPS." Further, the RD (Appendix C, para. 9) states: "The recommendation is that the Commission undertake a year 2008 review of progress toward the 25% goal, with the objective of modifying the RPS should the costs, benefits, or interplay with other State and Commission programs vary significantly from those forecast." The Joint Utilities are concerned that without a specific review mechanism, designed and revealed in advance of the RPS start, the uncertainty of this proposed review may have unintended negative impacts on the RPS. The undefined ability to modify the RPS in the future may cause renewable generators to view this as a potential risk and to respond with higher pricing to cover that presumed risk. The Joint Utilities support the concept of the 2008 evaluation, and would suggest that the evaluation not necessarily wait for 2008. Regardless of when, or how often, the RPS results are evaluated, there needs to be predetermined criteria for the evaluation in order to assure the various parties that their interests in the RPS will not be in jeopardy as a result of the evaluation.

Significant work remains to be completed to achieve a fair and workable RPS. The Joint Utilities believe a properly designed Implementation Process, with appropriate consideration of the schedule and review of milestones, is necessary to achieving the intended goals.

CONCLUSION

For the foregoing reasons, the Joint Utilities respectfully urge that the exceptions discussed herein be adopted by the Commission and incorporated into an RPS Policy Statement.

Respectfully submitted,

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Dated: June 23, 2004

ATTACHMENT A - STATEMENT OF THE CASE

By its Instituting Order,[1] the Commission announced the initiation of a proceeding to develop and implement a renewable portfolio standard ("RPS") in New York State. According to the Commission, the goals of its RPS efforts, as set forth in the Instituting Order, are to address "the effects on our climate of fossil-fired generation and the security implications of importing much of the fuel needed to supply our electricity needs." [2] An additional goal is to rectify the State's vulnerability to price spikes and possible supply disruptions as a result of its over-dependence on a finite supply of natural gas and other fossil fuels.[3]

In the Instituting Order, the Commission directed that an ALJ be appointed and that the ALJ facilitate a collaborative process with the goal of developing a draft policy statement.[4] The Commission also required the ALJ to provide periodic reports to the Commission Chairman concerning the status of the proceeding.[5] Additionally, the Commission directed the ALJ to obtain comments on a number of threshold issues identified in the Instituting Order.[6]

ALJ Eleanor Stein was assigned to this proceeding. On February 20, 2003, ALJ Stein issued a *Ruling Concerning Procedure and Schedule*,[7] in which she commenced the process for establishing the procedures and schedule for the proceeding. A *Notice of*

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1 Case 03-E-0188, *supra*, *Order Instituting Proceeding* (issued February 19, 2003) ("Instituting Order").

2 *Id*., *mimeo* p. 1.

3 *Id*.

4 *Id*., *mimeo* p. 5, Ordering Paragraph 1.

5 *Id*., *mimeo* p. 5, Ordering Paragraph 2.

6 *Id*., *mimeo* pp. 3-4.

7 Case 03-E-0188, *supra*, *Ruling Concerning Procedure and Schedule* (issued February 20, 2003).

Procedural Conference[8] scheduling a March 4, 2003 procedural conference was issued on the same day. At the ensuing conference, ALJ Stein explained the collaborative process she intended to follow in this case. ALJ Stein stated that she planned to schedule a series of educational seminars, followed by collaborative RPS design sessions.

Subsequently, ALJ Stein issued a *Ruling Revising Schedule*[9] on March 6, 2003. In that Ruling, she extended the time for filing comments addressing the threshold issues identified in the Instituting Order to March 28, 2003. Numerous parties submitted comments.

Following the submission of the comments referenced above, ALJ Stein convened several educational seminar sessions on April 7 and 8, 2003. The ALJ also facilitated a series of collaborative meetings in accordance with the schedule set forth in a *Notice of Collaborative Meetings.*[10] During these collaborative meetings, participating parties organized into various workgroups to address such issues as resource eligibility and the model to be implemented. The product of these workgroups was posted on the Commission's web site.

On June 9, 2003, a *Notice of Workshop on Cost Benefit Analysis Methodology*[11] was issued. The purpose of the June 27, 2003 workshop conducted pursuant to that Notice was to discuss the scope of the appropriate methodologies for assessing the costs and benefits of various renewable portfolio designs. The meeting focused exclusively on the cost study prepared by Staff of the Department of Public Service ("Staff").

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8 Case 03-E-0188, *supra*, *Notice of Procedural Conference* (issued February 20, 2003).

9 Case 03-E-0188, *supra*, *Ruling Revising Schedule* (issued March 6, 2003).

10 Case 03-E-03-E-0188, *supra*, *Notice of Collaborative Meeting* (issued March 27, 2003).

11 Case 03-E-0188, *supra*, *Notice of Workshop on Cost Benefit Analysis Methodology* (issued June 9, 2003).

A *Ruling on Motion to Amend Comment Schedule and Convene Reliability Impacts Meeting*[12] was issued on June 13, 2003. In that Ruling, ALJ Stein modified the schedule so that parties' comments concerning RPS design and cost issues would be prepared and filed in one set of comments. In the June 19, 2003 Ruling,[13] ALJ Stein outlined the process parties were to follow for their comments. Additionally, ALJ Stein issued revised working objectives.

By letter dated July 21, 2003, the schedule for the submission of cost studies and initial and reply comments was extended to July 28, August 20 and 29, respectively. Thereafter, on August 13, 2003, a technical conference was held to review various cost analyses prepared by several parties to this proceeding. Recognizing the complexity of the cost and benefit studies, and the importance of a studied RPS plan, ALJ Stein issued the August 18 Ruling[14] extending the time for the filing of initial comments until September 22, 2003. The ALJ's August 18 Ruling also instructed parties to file "any additional motions concerning schedule process, further meetings, or added procedure steps, no later than September 22, 2003."[15] At some point between the August 13, 2003 technical conference and the time that the parties submitted their comments concerning the studies, a decision was taken to revise the Staff studies and include the revised studies in the Draft generic Environmental Impact Statement that the Commission had previously directed be completed.

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[12] Case 03-E-0188, *supra*, *Ruling on Motion to Amend Comment Schedule and Convene Reliability Impacts Meeting* (issued June 13, 2003).

[13] Case 03-E-0188, *supra*, *Ruling Establishing Comment Procedures* (issued June 19, 2003).

[14] Case 03-E-0188, *supra*, *Ruling Granting, In Part, Motions to Amend the Comment Schedule* (issued August 18, 2003) (the "August 18 Ruling").

[15] *Id*., *mimeo* p. 2. The ALJ also noted that working groups still intending to file further reports may do so until September 15, 2003. The ALJ reserved decision on as to the appropriate filing date for reply comments. The Joint Utilities filed a request that a recommended decision not be completed until after further cost and reliability studies.

In a Notice[16] issued on September 19, 2003, the parties were advised of the scheduling of a conference concerning reliability on October 10, 2003. The purpose of the conference was a presentation by the New York Independent System Operator (the "NYISO") and discussion concerning the impact of additional renewable generation on the reliability of the bulk power system.

In a *Further Ruling Concerning Schedule and Procedure*,[17] issued September 19, 2003, the ALJ extended the schedule for submission of initial comments until September 26, and for the submission of reply comments until October 31, 2003. On September 26 and October 31, 2003, parties, including the Joint Utilities, filed initial and reply comments, respectively.

In a *Further Ruling on Procedure*,[18] issued October 21, 2003, the ALJ responded to a September 15th filing made by the Joint Utilities which requested a substantial revision in the schedule and procedure "then contemplated to bring the policy decisions inherent in this case to the Commission for determination."[19] The Joint Utilities "urged postponement of the issuance of a recommended decision until the reliability and cost considerations have again been aired by the parties or, in the alternative, that the recommended decision explicitly acknowledge that further development of information may require alteration of its recommendation."[20] The ALJ noted that, on October 10, 2003, an on-the-record parties' conference was held to explore the possible reliability

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16 Case 03-E-0188, *supra*, *Notice of Parties Conference Concerning Reliability* (issued September 19, 2003).

17 Case 03-E-0188, *supra*, *Further Ruling Concerning Schedule and Procedure* (issued September 19, 2003).

18 Case 03-E-0188, *supra*, *Further Ruling on Procedure* (issued October 21, 2003) (the "October 2003 Order").

19 *Id*., *mimeo* p. 1.

20 *Id*., *mimeo* pp. 1-2.

implications of the addition of substantial intermittent resources to New York's power market. The NYISO presented the scope and schedule for its comprehensive study of the reliability impacts issue and noted that the first phase reliability report would be available by the end of the year.[21] The ALJ stated that the first phase results of the NYISO study would be before the Commission before it makes its decision on an RPS policy. "Because this study will be available to the parties during the exceptions period and to the Commission in time for its finding to be considered in adopting an RPS policy, the request to delay the schedule for further analysis of reliability is denied as unnecessary."[22]

In the October 2003 Order, the ALJ also granted MI's request of October 8, 2003 for an on-the-record examination of cost studies. Per the ALJ, "[a]n on-the-record technical conference on the cost studies will be held following the completion of the Draft Environmental Impact Statement."[23] ALJ Stein also agreed that Working Group Four should be reconvened. However, the ALJ noted that development of the scope of effort for a reconvened Working Group Four was a concern, as was the composition of the group.[24] Parties were encouraged to consider these issues.

Staff moved for reconsideration of the October 2003 Order, and the request was granted, over the objections of several parties including the Joint Utilities, in the ALJ's *Ruling on Procedural Motions,* November 26, 2003.[25] In this Order, the ALJ stated that "[t]he concern expressed by parties that they have a meaningful opportunity to review

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21 *Id*., *mimeo* pp. 2-3.

22 *Id*., *mimeo* p. 3.

23 *Id*. The ALJ further stated that she expected to schedule the technical conference for January, 2004, and that she expected the Recommended Decision to be issued by then.

24 *Id*., *mimeo*, p. 4.

25 Case 03-E-03-E-0188, *supra*, *Ruling on Procedural Motions* (issued November 26, 2003).

and comment upon the most recent cost studies practicable, prior to the completion of a recommended decision, is compelling and parties' motions seeking this opportunity are granted and the October 21 Ruling is so modified."[26] ALJ Stein noted that Staff expected to complete the next iteration of its cost study by late January 2004, and that an on-the-record technical conference for discussion of that new cost study and limited supplemental comments would immediately follow.[27]

With respect to the reliability study, the ALJ stated that "[a]s represented to me in correspondence of November 24, 2003, the first phase of the New York State Energy Research and Development Authority ("NYSERDA")/NYISO Study will be completed and released in final form by January 31, 2004. A technical conference on the reliability study will be held shortly after its release, followed by a supplemental filing by parties limited to these issues."[28] The ultimate result was that revised Staff Cost Studies were issued on February 19, 2004, revised on February 25, 2004 and supplemented on March 9, 2004. Regarding the motions and proposals of certain parties to hold in abeyance submission of a recommended policy decision to the Commission until after the completion of the Phase II NYSERDA/NYISO Study, the ALJ stated that "decision is reserved…".[29]

On February 13, 2004, a *Notice of Technical Conference*[30] was issued, which established a March 8, 2004 technical conference "to afford parties the opportunity to discuss with and question GE Power Systems Energy Consulting and NYSERDA

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26 *Id.*, *mimeo* p. 7.

27 *Id.*

28 *Id.*

29 *Id.*

30 Case 03-E-03-E-0188, *supra*, *Notice of Technical Conference* (issued February 13, 2004).

regarding the Phase 1 Report released February 2, 2004, 'The Effects of Integrating Wind Power on Transmission System Planning, Reliability and Operations.'"[31] The notice also stated that parties would have until March 18, 2004 to file supplemental comments regarding the Phase I Report and the issues discussed at this technical conference. The Joint Utilities filed the "Joint Utilities' Comments on NYSERDA/NYISO Preliminary Overall Reliability Assessment" in accordance with the February 13th notice.

By letter dated March 1, 2004, the ALJ invited parties to propose, by March 8, 2004, schedules for discovery, a technical conference, and filing supplemental comments concerning the Staff Cost Study. The March 1 letter also suggested that parties serve interrogatories and that Staff would respond at a cost study technical conference, which was tentatively scheduled for March 17, 2004. By letter dated March 8, 2004, the Joint Utilities, in conjunction with a number of other parties, filed their suggestions with respect to the establishment of a schedule for the examination of the Staff Cost Study.

In the *Further Ruling Establishing Schedules*,[32] issued March 10, 2004, ALJ Stein stated that the March 17, 2004 Technical Conference on the Staff Cost Study would be held and may continue the following day, as necessary. The ALJ also noted that there would be one round of supplemental comments concerning the Cost Study Report II, Volumes A and B which must be filed by April 8, 2004. A *Notice of Technical Conference*[33] was also issued on March 10, 2004. On March 17 and 18th technical conferences were held.

31 *Id.*, *mimeo* p. 1.

32 Case 03-E-03-E-0188, *supra*, *Further Ruling Establishing Schedules* (issued March 10, 2004).

33 Case 03-E-03-E-0188, *supra*, *Notice of Technical Conference* (issued March 10, 2004).

On March 24, 2004, in the *Ruling Establishing Format for Supplemental Comments on Cost Study Report II,*[34] the ALJ established a common format to be used by all parties filing supplemental comments concerning the Cost Study Report II. On April 8, 2004, the Joint Utilities submitted the "Joint Utilities Supplemental Comments on Cost Study Report II."

In the *Ruling on Motion to Further Postpone*,[35] issued April 7, 2004, the ALJ responded to the comments of parties which "restated or raised additional reasons to delay preparation of a recommended decision and a Public Service Commission policy statement concerning adoption of a renewable energy portfolio standard for New York State."[36] According to the ALJ, "[t]hese parties assert that the recommendation or a policy statement in this proceeding require the completion of Phase 2 of the reliability report, expected in December 2004, and additional cost studies, technical conferences, and comments."[37] "Based upon a review of the status of the extensive record, compiled in part in response to parties' concerns, and the necessity for timely policy recommendations and decisions to the State's renewables development, among other reasons, the motion is denied."[38]

On April 8, 2004, the Commission issued an *Order Concerning Draft Generic Environmental Impact Statement*.[39] It stated that a Draft Generic Environmental Impact Statement ("DGEIS") would be issued by the Secretary and filed for publication. The

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34 Case 03-E-03-E-0188, *supra*, *Ruling Establishing Format for Supplemental Comments on Cost Study Report II* (issued March 24, 2004).

35 Case 03-E-03-E-0188, *supra*, *Ruling on Motion to Further Postpone* (issued April 7, 2004).

36 *Id.*, *mimeo* p. 1.

37 *Id*., *mimeo* pp. 1-2.

38 *Id*., *mimeo* p. 2.

39 Case 03-E-03-E-0188, *supra*, *Order Concerning Draft Environmental Impact Statement* (issued April 8, 2004).

DGEIS was subsequently made available to parties via the Commission's web site. The Joint Utilities filed comments on the DGEIS on May 14, 2004.

On June 3, 2004, the Secretary issued the RD of ALJ Stein. An *Erratum Notice* was issued on June 16, 2004.