Renewable Portfolio Standards
Background and Analysis
For New York State

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Background: In mid-April 2002, in response to a request by the New York State Department of Public Service, NYSERDA posed several questions relating to the Renewable Portfolio Standard as a policy and its potential application in New York, and requested a quick, concise and objective response based on the team's assessment of RPS experience.

As presented in the conclusions, removing impediments to the green power market should be given priority by NYSERDA and utility regulators. One of the principal advantages of the green power market, relative to an RPS, is that it may be able to generate a *sustainable* market for new renewable generation in New York that is not tied to ongoing publicly funded financial incentives. It may also help educate New Yorkers of the potential use and value of renewable energy in the state. Accordingly, while we believe that new renewable generation delivered from a *carefully crafted and effectively implemented RPS* would outstrip that delivered by the green power market, both strategies have merit and deserve close, ongoing attention.

Where have RPSs been employed? What has been the experience to date? What other states are in the process of implementing an RPS?

RPS mandates or similar renewables purchase obligations have been established to date in 12 states: (a) 7 states in a retail choice environment (AZ, CT, ME, MA, NV, NJ TX); (b) 3 states have adopted renewable energy purchase mandates in a regulated monopoly setting (IA, MN, WI); and (c) 2 additional states have similar mandates on the provider of last resort (NM, PA). The experience in each of these states is summarized below.

<u>**Retail Choice Environment**</u>

- Arizona:
    - **Experience Overview:** A small RPS focused in large part on new solar power began in 2001. Until 2004, the standard applies only to the utility distribution companies (IOUs are automatically covered under the RPS, rural coops are covered but can request various exemptions, while municipal utilities are exempt from the RPS altogether); in 2004 all retail suppliers in competitive markets are required to meet the RPS. Costs of the RPS may be recovered in part through SBC funds and in part through an "Environmental Portfolio Surcharge" on electricity bills. There are at present no penalties for non-compliance, and as a

result some utilities have not been in full compliance with the requirement. A cost-benefit analysis of the policy in 2003 will dictate whether it continues in 2004 and beyond.

- **Status:** Commission order in April 2000, with rulemaking finalized in early 2001. RPS became effective in 2001.
- **Effectiveness to date:** Solar activity in the state has been driven by the RPS, with approximately 3 MW of solar installed so far under the RPS. Approximately 10 MW of landfill gas has also come on line, in part to meet the RPS requirement, and several additional MW of biomass are currently planned. Solar capacity in the state is steadily and sizably increasing by virtue of the RPS, and some trade in "private label" renewable energy credits has occurred. Renewable energy stakeholders appear generally happy with the results to date, though some problems have also emerged. While the utilities have generally fully complied with the non-solar component of the RPS, they have not fully complied with the solar fraction (the solar fraction is initially set at 50% of the total requirement). The lack of full compliance is in large part a result of there being no penalties for non-compliance. Instead, utilities have simply used funds collected by the SBC and the Environmental Portfolio Surcharge to purchase and install PV systems, often in a central-station mode rather than on end-use customer premises. By issuing RFPs for the use of these funds, the utilities have obtained a large number of proposals from solar vendors. If compliance can not be met through the use of these dedicated funds, however, there has been little incentive to achieve compliance through other means. Additionally, the planned cost-benefit analysis of the policy in 2003 raises substantial uncertainty about the fate of the RPS on a longer-term basis. Given this, utilities have thus far avoided potentially more cost-effective but larger solar projects (solar thermal electric, for example) because of the necessarily longer-term and more sizable commitment that would be required for such systems than the smaller PV systems currently used to achieve partial compliance.
- **Prognosis:** The RPS must meet a commission-approved cost-benefit point in 2003 in order to be continued after 2004. This imposes great uncertainty on the renewable energy market in the state. As long as the RPS stays intact, it will continue to drive substantial solar PV generation in the state. In part because the standard was established via regulation, however, the utilities have and will likely continue to argue before the Arizona Corporation Commission that the standard is too stringent and should be loosened. The lack of a specified penalty for non-compliance, at least until 2004, is of concern; there has been some discussion about the possibility of creating a non-compliance penalty after the cost-benefit analysis of 2003 is complete. If the ACC sends a clear signal that the RPS will continue for a period of 5-10 years, utilities may have an incentive to invest in larger, and more cost-effective solar thermal options in the future, as opposed to the PV systems currently employed.

- Connecticut:
    - **Experience Overview:** A two-tier RPS (Class 1 increasing percentage; Class 2 stable percentage) nominally started in 2001, but the PUC has established that the

RPS legislation does not apply to standard offer and default service, which means that the majority of load (over 99%) is exempt. Individual suppliers may also petition the PUC for a delay in RPS targets of up to 2 years; the PUC has denied at least one petition for delay. In conjunction with these flaws, weak enforcement penalties lead many to believe that Connecticut's RPS as originally drafted will not have much of an impact on renewable energy supply. A fixed-price standard offer available to customers who do not switch suppliers has been set at a level insufficiently high to attract retail competition. Only 2 small retail efforts are present in the state, both selling green power (one also selling commodity offering). However, the fixed-price standard offer expires at the end of 2003. Two bills are currently being debated in the legislature that would ensure that the RPS applied to the default service supplier thereafter. Both would delay the ramp-up of the Class 1 percentage and expand geographic eligibility, and at least one would establish penalty mechanisms and alternative compliance payment requirements, and expand application of the RPS to underutilized biomass capacity.
  - **Status:** In place and currently applicable.
  - **Effectiveness to date:** Totally ineffective. Little or no renewables have resulted to date or are being financed in anticipation of the requirement.
  - **Prognosis:** Prospects are poor without legislative fixes, but it appears legislative fixes are being considered to address most major flaws. If passed, these are expected to make the RPS an effective policy by the end of 2003. There appears to be consensus on the major aspect of the legislation to fix the RPS, but it is possible other energy issues could lead to no action being taken.

- Maine:
  - **Experience Overview:** The RPS took effect in March 2000, at a stable 30% requirement. Eligible resource supply (which includes fossil cogeneration) far exceeds RPS requirements - the historical mix in Maine reflected 40% eligible resources, and uncommitted eligible resources throughout the region abound - rendering Maine's RPS effectively meaningless. While all suppliers have complied, premium revenues available to renewable generators have been extremely limited. In addition, the RPS will be re-examined by the PUC (with recommended changes to the legislature) after 5 years. Compliance has been based on contract path until now, but will soon utilize the NEPOOL Generation Information System (G.I.S.).
  - **Status:** In effect since 2000.
  - **Effectiveness to date:** Has failed to lead to any new renewable resources, and has failed to generate significant revenues above commodity electricity market prices for existing renewable generators to help them survive in competitive markets. Widely considered a failure due to non-binding percentage, over-broad eligibility, and no provisions to encourage new renewables.
  - **Prognosis:** There is general agreement that the RPS is not working effectively, and stakeholders are proposing alternatives ranging from fixing the RPS to dropping the RPS in favor of an SBC-funded renewables program.

- Massachusetts:
  - **Experience Overview:** After several years of study, the Division of Energy Resources released final RPS regulations in March 2002. The RPS standard is for an increasing percentage of eligible new renewables, and incremental production at existing units over an historic generation baseline. Legislative language suggests a standard might be established to maintain the historical contribution of renewables, but the Division of Energy Resources chose not to establish a baseline standard due to surplus regional supply. This feature has been very controversial and may still be the subject of challenge. The legislature subsequently required DOER to study over the next year whether to establish a baseline requirement. There has been significant controversy over biomass eligibility due to ambiguous legislative language, and disgruntled biomass generators are considering seeking an injunction over unfavorable interpretations.
  - **Status:** The standard takes effect in 2003 at 1% of sales. Early compliance banking may start during mid-2002 once the NEPOOL G.I.S. is up and running.
  - **Effectiveness to date:** Too early to tell. Some landfill gas generation is being brought on-line to serve RPS load, much on a merchant basis, others seeking long-term contract. Increased production is being sold in 2002 from 2 existing but underutilized fluidized bed biomass plants for early compliance purposes. Some wind developers are seeking contracts and/or permits, but none appear likely to be developed on a merchant basis. Some quasi-merchant New York wind (Madison, Fenner) is looking to Massachusetts as a market, but it is unclear how they will deal with difficult scheduling/transmission/operational barriers inherent in “external unit contract” requirements.
  - **Prognosis:** Final rules were issued with insufficient lead-time to build new renewable resources in time for first year compliance. Today and in near future, Standard Offer (SO) and Default Service (DS) constitute the vast majority of sales. While the distribution utilities are subject to the RPS requirement, they buy supply for SO and DS on a short-term basis, and are pushing the requirement up to their wholesale suppliers. This results in a lack of any party in the market willing to enter into the long-term contracts necessary to finance new renewables. As a result, and due to limited merchant renewable generation being available and difficult siting prospects, there is some possibility of a near-term shortage. In this environment, many parties subject to the requirement anticipate paying the 5¢/kwh alternative compliance payment to the Massachusetts Renewable Energy Trust. Rules appear to be sufficient to support addition of new renewables and a functional RPS in the long run. Ultimate costs are heavily dependent on ability to site generation within New England and the cost and operational impediments to imports. It is unclear whether a baseline standard will ultimately be established.

- Nevada:
  - **Experience Overview:** The Nevada RPS is the nation’s most aggressive standard, increasing from 5% in 2003 to 15% in 2013. At least 5% of the purchase standard must be met with solar power. Administrative fines may be imposed on those retailers that do not comply with the RPS.

   - **Status:** SB372 signed into law in June 2001, revising an earlier RPS proposal. RPS rules initially adopted in December 2001 were rejected by the legislature because of the imposition of a cost cap. Nevada PUC now revising regulations to remove the cost cap.
   - **Effectiveness to date:** Regulations required Sierra Pacific and Nevada Power to hold their first solicitation for renewables in late 2001; they received 49 proposals for 4,300 MW of eligible bids, reportedly at very competitive prices. 3000 MW of wind, 385 MW of solar, and 784 MW of geothermal and biomass were submitted. Nevada Power has recently signed a 17-year PPA with an 85.5 MW wind project to be built at the Nevada Test Site, expected to be operational in 2003.
   - **Prognosis**: The Nevada RPS is beginning to drive renewable energy supply, though the RPS regulations still contain some uncertainties – mostly involving costs, contract reasonableness, and cost recovery. Assuming that the regulations are developed as expected, the Nevada RPS is likely to be a major driver of renewables development in the state absent legislative or regulatory changes.
- New Jersey:
   - **Experience Overview:** Interim regulations were issued in June 2001; final regulations must be issued within 18 months (i.e., by the end of 2002). A two-tier RPS (Class 1 increasing percentage; Class 2 stable percentage). The standard, and compliance with the standard, got a late start due to delay in release of interim regulations beyond the original legislative deadline. This left negligible lead-time for construction of new renewables. However, sufficient merchant renewables (existing landfill gas and recently constructed wind) are in place to meet the fairly low initial Class 1 percentages. There is currently sufficient existing supply to meet the standard; this situation will begin to change in earnest in 2006 and 2007, when the standard begins to accelerate. While the interim standard relies on a contract path approach to demonstrating compliance, it foreshadows that the final rule may allow for compliance by tradable credits. The interim regulations require makeup of any shortfall, and ultimately provide for loosely defined penalties to be applied to those failing to comply (fairly week teeth).
   - **Status:** The standard went into effect in the final quarter of 2001. Interim regulations in effect.
   - **Effectiveness to date:** Due in part to availability of merchant class 1 renewables, the RPS is now proceeding without a hitch. Little additional new generation is currently being brought on-line to meet the standard. Price premiums appear fairly low and stable.
   - **Prognosis:** It is somewhat early to tell, but it appears that this standard is reasonably well designed and has the eventual makings of a workable and successful policy. As the Class 1 percentage increases over time, the standard will eventually soak up the merchant renewables available in the region and become binding, causing the construction of new renewables. The state of NJ and others are investigating with PJM the possibility of establishing a tradable credits system to support RPS compliance.

- Texas:
    - **Experience Overview:** Texas is widely considered to have the most successful RPS in the nation. The RPS requires 2000 MW of new renewables capacity to be installed by 2009, contains strong penalties for non-compliance, and uses credit trading and flexibility mechanisms to lower costs. The MW goals are translated into MWh-based purchase obligations, and the standard applies to all competitive and default suppliers of electricity in the Texas competitive market. A substantial amount of renewables capacity came on line in 2001 because of the RPS, and wind power costs are lower than 2.5 cents/kWh in some contracts.
    - **Status:** Restructuring legislation in 1999 contained the RPS, with an interim RPS rule finalized in early 2001. The RPS took effect beginning in 2002, with the credit trading system operational in May 2001.
    - **Effectiveness to date:** 915 MW of wind power came on line in 2001, much of it to satisfy the RPS. The 850 MW standard for 2005 has been met 4 years early. This relative oversupply is expected to keep compliance costs low, and wind contracts have been signed for less than 2.5 cents/kWh. The largest utilities have opted to meet their obligations by purchasing renewable energy and credits together under long-term (10-20 year) contracts. New, competitive suppliers will likely meet their obligations by purchasing credits from the secondary market.
    - **Prognosis**: The Texas RPS will continue to drive renewable energy development in the state. However, because utilities are well over-compliant, renewables development is expected to slow from its hectic pace in 2001. Nonetheless, a number of utilities are preparing for new renewables solicitations in the state, in part to meet future RPS obligations and in part because of the low cost of wind power.

<u>Regulated Monopoly Setting</u>

- <u>Iowa:</u> Iowa's Alternate Energy Production Law (1983, revised in 1991) required Iowa's IOUs to purchase 105 average MW (aMW) of wind power. The utilities met this requirement several years ago with 250 MW of wind power, and as a result the purchase requirement is no longer "active" on a going-forward basis.
- <u>Minnesota:</u> Minnesota's Radioactive Waste Management Law in 1994, and subsequent PUC regulations, require Xcel Energy (previously NSP) to purchase wind power as part of a radioactive waste storage settlement. 425 MW of wind, and 125 MW of biomass were required by 2002; these requirements have been met. The PUC has signaled that an additional 400 MW of wind will be required by 2012.
- <u>Wisconsin:</u> Wisconsin's RPS was established in a regulated market setting, and increases from 0.5% in 2001 to 2.2% by 2011. A limited renewable energy credit trading system is being established, and some credit trade has already occurred. The standard has been in effect since early 2001, could support 300-400 MW of wind by 2011, and new wind and LFG projects have already come on line in Wisconsin and Iowa to satisfy the RPS (53 MW of wind and 10 MW of LFG installed in Wisconsin - most due to policies that preceded the RPS - and 80 MW in Iowa). The utilities are currently well over-compliant with the RPS, raising concerns that several years of market stagnation may follow before additional renewables capacity is added. Also, because renewable energy credit banking is allowed, the current over-compliance may be banked and used in future compliance periods. The result is that few

incremental renewable energy investments may be needed for a number of years. A second concern raised by renewable stakeholders is that of the location of the renewable energy investments - because less expensive renewable energy options are located out-of-state, Wisconsin may be exporting some of the benefits of its RPS.

<u>Mandates on Provider of Last Resort</u>

- <u>New Mexico:</u> Restructuring legislation required the PRC to study the imposition of an RPS. The original RPS (a 5% requirement on the standard offer provider) designed by the PRC was delayed, along with restructuring, until 2007. In the meantime, the PRC staff has proposed to revise the RPS into one that would take effect in September 2003 at 2%, and increase to 10% in 2007 and thereafter. The RPS would cover all electricity suppliers under the jurisdiction of the PRC, and would therefore cover competitive supplier after restructuring is introduced (currently slated for 2007); utilities would be covered under the RPS in the meantime. The proposed RPS is still in the rulemaking phase.

- <u>Pennsylvania:</u> Pennsylvania established a renewable energy purchase requirement on a limited amount of competitively bid default service providers in several utility restructuring settlements. For PECO, West Penn, and PP&L, 20% of residential customers covered under competitive default service are to be faced with a 2% renewables purchase requirement in 2001/2002, rising 0.5% per year. For GPU, an 0.2% purchase requirement is to apply to 20% of customers in 2000 rising to 80% of customers in 2003 and thereafter. The requirements may be lowered is they would otherwise increase default service costs by over 2%. Because Pennsylvania has been unable to attract competitive default service providers to the degree that they had wanted to, and because the renewable purchase requirements may be met with existing generation and lack many design details, the impact of the requirements has been minimal and is expected to remain minimal for some time to come. Only approximately 50,000 residential customers in the entire state are currently served by a competitive default service provider (Green Mountain Energy in PECO's service territory) and are therefore subject to the renewable energy purchase mandate. Meanwhile, 200,000 customers previously served by New Power under competitive default service are being returned to PECO's utility default service, while in other service territories RFPs for competitive default service have received no viable supplier bids that can beat the utility offers. Consequently, the renewable requirements in Pennsylvania have not been a driving factor for the new renewables development in the state.

<u>In the Works?</u>

Many other states are considering similar measures. Though many of these requirements may never be imposed, the examples include:

- <u>California:</u> Legislation that would create an RPS was debated in 2001 and is being reconsidered in 2002 with a reasonable chance of success. Even without legislation, with the competitive retail market shut down, the PUC is considering whether to establish a purchase mandate by regulatory action that would apply to the major IOUs. PUC has enabling legislation giving them specific authority to establish renewables set-asides, which would support their taking action if the legislature does not.

- Colorado: This state is considering an RPS in 2002. An initial attempt was rejected by the legislature, but on April 29, 2002, the state Senate passed SB 180 providing for an RPS ramping up to 10% by 2020. It next goes to the House for consideration.
- Hawaii: An RPS was proposed in legislation in 2000 and 2001. Instead, Hawaii adopted a non-punitive "goal" of 7% by 2003, 8% by 2005, and 9% by 2010 (includes existing renewables). The effectiveness of such a "goal," without noncompliance penalties, is not yet clear. Utilities must file regular reports to the legislature to document their progress towards meeting the goals, and this may provide sufficient incentive for some incremental renewables development. The utilities have not issued any green RFPs yet, however, though there have apparently been some positive signs from utility staff. At present, there is no expectation that the PUC would enforce the goal absent specific legislative guidance to do so.
- Illinois: This state established a legislative "goal" for 5% of state load from renewables by 2010, 15% by 2020. However, there is not yet any implementation mechanism adopted. It remains unclear whether this goal will remain just that, or whether the PUC will take the legislative goal as a means by which to establish a real renewables purchase target, a means for penalizing noncompliance.
- Iowa: An RPS was proposed in 2000 as part of restructuring legislation, which did not pass the state legislature. Restructuring legislation and an RPS are considered unlikely in the coming year, though a Governor's task force recently recommended a goal of 1000 MW of renewables by 2010 (without establishing a mechanism to reach that goal).
- Maryland: Considered an RPS in 2000, and have completed a study of the policy. No action has been taken to adopt a RPS yet.
- Minnesota: The legislature passed a non-binding goal of 1% in 2005, increasing each year to 10% in 2015. No mechanism was established to require compliance towards the goal, and the goal now operates on the good faith efforts of the utilities. The PUC has not addressed this issue yet, as the law was passed not long ago, but there is a possibility that the renewable energy goal would be considered in utility IRP proceedings with the PUC. However, some stakeholders believe that further legislative guidance would be necessary for the PUC to feel comfortable with its authority to enforce the rule.
- New Hampshire: An RPS was considered in draft legislation in 2001, but has not come out of committee. The legislator driving the activity recently hinted that they are waiting on the Massachusetts experience before proceeding.
- Rhode Island: An RPS is being discussed as a possible tool for the Greenhouse Gas Action plan, and has been floated in a bill that lacks significant support, so an RPS does not appear likely at this time.
- Oklahoma: The legislature was crafting an RPS bill for consideration, but the RPS was shot down in 2002.
- Utah: An RPS is being considered in Utah, but is still in the early stages of consideration.
- Vermont: Vermont was one of first states to consider RPS in legislature. There has been some interest in the Senate, but restructuring legislation did not pass.

1. In New York, utilities divested the generation business from their distribution business. In other states that have implemented RPS policies, was generation divested as in NY or did the utilities remain integrated and/or in the competitive energy markets? How have these differences in competitive market structure impacted the RPS in these states?

In three states - Arizona, Nevada, and New Mexico – there was no divestiture of utility generation associated with electric restructuring. In New Jersey, divestiture was not required, but GPU chose to divest, PSE&G spun its generation into a separate company, and Conectiv divested some generation and held onto the rest. In Pennsylvania, divestiture was not required, but there was a moderate degree of voluntary generation asset divestiture. In Texas, restructuring rules mandated a divestiture of at least 15% of each utility's generation, as well as functional separation of the remaining generation from the distribution utility function. Connecticut, Maine, and Massachusetts each required generation divestiture. However, in Connecticut utility affiliates were allowed to bid on, and did in fact acquire, some of their former generation.

Due to the early stages of RPS implementation in many states, the specific impacts of divestiture on the RPS have not been visible everywhere. However, experience in Texas, New Jersey, and Massachusetts hints at the impact one might expect as a result of this feature of electric restructuring.

- <u>Texas:</u> While competitors have been allowed into the market, incumbent utilities have remained more or less integrated and serving significant portions of load. The economics of wind power are quite favorable in the region (high winds and no land-use conflicts). In this environment, developers have found that utilities have been willing to enter into long-term contracts (10-20 years) for power and renewable energy credits. The presence of buyers sufficiently creditworthy to allow project finance backed by these contracts has been a big factor in the early success of the Texas RPS, as has been the availability of low-cost renewable resources.
- <u>New Jersey:</u> Recent activity suggests that the partial divestiture may not be a major factor in the success of the RPS policy, at least in part because there appears to be sufficient merchant or quasi-merchant[1] renewables available in PJM (NY renewables are also eligible and there are merchant renewables available in NY as well). In addition, "basic generation service" (BGS), the utility offer received by those not choosing competitive supply, has been put out to bid to a number of credit-worthy generation companies or marketers, all of whom are committed to RPS compliance and are now willing to enter into short-term contracts.
- <u>Massachusetts:</u> In Massachusetts, divestiture appears to be causing some problems in the near-term for the RPS. The RPS requirement commences in 2003 and the rules have just become effective in late April 2002. A minority of load has chosen competitive supply, and this supply comes from suppliers often with questionable credit-worthiness. The utilities put standard offer and default service up for bid on a periodic basis for very short-term (6-month)

[1] meaning a wholesale marketer of generation company has entered into long-term contracts sufficient for financing on a speculative basis.

contracts and are pushing the RPS requirement to these suppliers, and the solicitation for service in 2003 has not occurred yet in most cases. In the absence of substantial merchant renewables activity, this leaves renewable generators with little lead-time, and almost no credit-worthy buyers with RPS obligations with whom to enter into contracts necessary to finance projects. (At some point, we expect this situation to lead to high enough market prices for renewable credits that credit-worthy middlemen will ultimately take on the risk of a long-term position).

Our conclusion on this matter is that it is important to have credit-worthy buyers in place to allow long-term contracts and renewables financing. However, the presence of merchant renewables and/or low-cost renewables[2], combined with sufficient lead-time and buyers with long-term obligations, can overcome the lack of credit-worthy long-term buyers that results from generation divestiture in the presence of nascent retail competition.

We also strongly recommend that utility regulators play a forceful role in the RPS compliance obligations of the standard offer and default service providers. These providers remain regulated, even after restructuring commences, and utility regulators should be responsible for approving RPS compliance plans and assuring adequate cost recovery. More than utility divestiture, lack of regulatory oversight appears to be the major impediment to long-term contracts in Massachusetts. With appropriate regulatory incentives, requirements, and cost recovery, we do not believe that utility divestiture of generation assets should be an impediment to long-term contracting for renewable generations.

2. Was the RPS enacted through legislation or regulatory Commission mandate? Has this made a difference?

The majority of the RPS requirements described under Question 1, above, were established via legislation and implemented through utility regulation. There are several exceptions to this approach. Specifically, 3 states have established the RPS through regulation, without specific RPS legislation in place:

- <u>Arizona:</u> Arizona’s RPS was established via regulation, not via legislation. Nor did the Arizona Corporation Commission have legislative guidance directing them to study the RPS. Arizona's RPS was the outgrowth, in part, of a long-term IRP process that had created renewable energy goals for the utilities as early as 1992. It deserves note that the ACC's jurisdiction on these matters is arguably stronger than in other states. The ACC and its jurisdiction were created in the Arizona constitution, whereas most other regulatory commissions have been established by legislation. According to ACC staff, the origin of their commission gives them clearer and stronger jurisdiction than in other states.
- <u>New Mexico:</u> New Mexico’s original renewable energy purchase requirement that was to be imposed on standard offer service was developed by the PRC. As this purchase requirement has been legislatively delayed, along with restructuring as a whole, the PRC is currently developing another RPS for possible implementation in 2003. New Mexico’s restructuring

[2] e.g. partially spurred by SBC action in PJM.

legislation did contain several positive statements towards renewable energy, defined renewable energy, and directed the PRC to examine "the advisability and desirability of requiring renewable energy portfolio standards in the supply service offered to customers in the state…" The PRC took this language as sufficient authority to develop an RPS at the regulatory level. In recent comments to the RPS on the proposed RPS, several electric utilities questioned the PRC's authority to implement the RPS under either the state's Public Utilities Act or its future replacement, The Restructuring Act.

- Pennsylvania: Pennsylvania electricity restructuring legislation did not contain any renewable energy purchase requirements. However, the legislation required the PUC to establish electricity reform settlements with each of the IOUS. As part of these regulatory settlements, renewable energy purchase requirements were imposed on a subset of the utilities. Because these settlements were agreed to by all parties involved, this was not a case of the PUC asserting its jurisdiction on the matter of renewable energy requirements. The experience therefore may hold little precedential value for New York.

There is not sufficient experience with the RPS in the above three states, or in other states, to clearly say whether the initiation of an RPS by legislation or regulation is a superior approach. Legislatively established RPS requirements have failed (Maine, Connecticut, etc.), and they have succeeded (Wisconsin, Texas, etc.). The same can be said for the RPS requirements imposed by regulation – the Arizona RPS appears somewhat successful, while the Pennsylvania mandate was designed poorly and the fate of the New Mexico RPS remains unclear.

While it appears that renewable purchase requirements imposed by regulation may be possible and can function reasonably well, several key observations are apparent:

- Jurisdiction is critical. The regulator must have the jurisdiction to impose such a requirement. As a general rule, regulators do have the jurisdiction to oversee and regulate the supply planning of the IOUs. Whether this jurisdiction extends to publicly owned utilities and competitive suppliers is less clear and varies by state. At the least, most PUCs have no jurisdiction over publicly owned utilities, ensuring that the RPS would not apply to a segment of the market. Moreover, in a competitive retail marketplace, the regulator would require some regulatory hook through which to apply an RPS, e.g. if a PSC has been given jurisdiction over issuing and revoking licenses to sell at retail, this licensing requirements can be a source of jurisdictional leverage on suppliers to implement and enforce an RPS as a condition of licensing (as we discussed in our earlier memo). Even where a regulator might have this jurisdiction, however, experience shows that regulators are often extremely reticent to use their jurisdiction liberally. In fact, of the three examples offered, both Pennsylvania's (utility settlement) and Arizona's (constitutionally enabled commission) experience have only limited relevance to the New York situation.

- Positive politics. Perhaps as important, the regulator must be sure that the specific requirement that they are imposing is not viewed as so objectionable by those on which it is imposed or those in the legislative or executive branches of government that the requirement will be overthrown legislatively. Even if the regulator has the official jurisdiction to impose the requirement, if the legislature is overtly opposed to the requirement they will likely win out in the political battle that ensues.

- Shifting regulatory preferences. One major concern of RPS requirements imposed by regulation is that utility regulation is often subject to greater flux and energy legislation. An

RPS established by regulation may therefore be more amenable to regular revisions or elimination than one imposed by legislation, especially as the make-up of the regulatory commission changes.

- Staff expertise. A counteracting force is that regulatory commissions, if dedicated to an RPS, may be able to implement a more effective RPS than legislators. Legislation is subject to many outside political interests, and lack of legislative expertise in renewable energy policy matters is one of the reasons that many of the existing state RPS policies have proven inadequate. Energy regulatory commissions are more sophisticated in their understanding of these issues, and may therefore be able to avoid the design flaws inherent in a number of RPS laws around the nation. Similarly, staff of the ACC have mentioned that establishing their RPS by regulation required convincing two of three commissioners, rather than a majority of 90 legislators.

3. Does the RPS apply only to utilities or to all load serving entities, including aggregators, marketers, and municipal and public power authorities? What is the impact of different policies?

State RPS obligations have to date been applied to entities directly serving retail load. Hence public power authorities, which are typically wholesale suppliers, have generally not been subject to RPS requirements. The obligation can generally only fall at one point in the chain of title. For this reason, load aggregators (which do not take title to the energy) have not been subject to RPS, since the retail suppliers actually taking title before retail sales to the end-users aggregated by the aggregator would be subject to the requirement; to also subject aggregators would be to impose the obligation twice for some electricity customers. Applicability in the states we have identified can be summarized as follows:

- In Massachusetts, Nevada, New Jersey, Texas, and Maine, the RPS is applied to all entities serving retail load except public power entities – municipal light plants and cooperatives – that are exempted from the states' electricity reform measures. (In Texas, if a muni or coop opens their market to competition, then the muni or coop must meet the RPS.)
- In Arizona, the RPS applies directly only to IOUs until 2004. REPs are exempt until 2004. Coops are initially exempt from the RPS, but are collecting the Environmental Portfolio Charge and must submit RPS plans to the ACC or ask for continuing exemptions (in Arizona, the coops are subject to ACC regulation). Munis and the Salt River Project are outside of the ACC's jurisdiction, and are therefore exempt.
- In Connecticut, the legislative language was written sufficiently loosely that Standard Offer and Default Service supply was exempted (this was not the apparent attempt, and bills are now being debated to close this loophole). Municipals and cooperatives are also exempt.
- In Iowa a state without retail competition, the RPS applies only to investor-owned utilities.
- In Wisconsin, the RPS applies to all IOUs and munis and coops, with limited exceptions.
- In Minnesota, the purchase mandate results from a settlement and applies only to Northern States Power (Xcel Energy).

- In New Mexico, the original RPS was only to apply to standard offer service providers. However, a new RPS proposal by the PRC would apply the RPS to all IOUs and also to REPs once retail competition is introduced.
- In Pennsylvania, the renewable purchase obligation only applies to certain competitive default suppliers.

Public power entities are almost always exempt from RPS requirements, which are frequently established in an electricity reform process focused on the IOUs and implemented by PUCs that have little or no jurisdiction over publicly owned utilities. The only exceptions to this are Wisconsin, where the RPS does apply to public power, and Arizona in which rural coops (but not munis) may apply for exemptions but are not automatically exempt. In some states, the RPS has been designed in way such that if and when a publicly owned utility opens its market to competition, then the RPS would apply to those utilities (examples include Texas and Massachusetts)**.** In other cases, if a publicly owned utility pursues customers outside of their service territory, they would become subject to the RPS within their service territory (e.g. in Massachusetts).

The relative impact of various approaches to the application of the RPS can be severe. Connecticut provides the best example, where an exemption of standard offer and default service has made the RPS moot - only competitive retailers have been required to meet the RPS, negatively impacting the competitive market and ensuring that the policy has little impact on renewable energy development. The conclusion from this experience is clear: RPS requirements should apply to both competitive marketers and to standard offer and default service providers.

Exemptions are frequently provided to publicly owned utilities (munis, coops, etc.). Experience shows that such exemptions do not gut the effectiveness of an RPS policy. Of course, applying the RPS to all LSEs would be the "fairest" approach, and would ensure that all who benefit from the renewables development in the state also pay for that development. Applying the RPS to all LSEs would also ensure that renewables development is maximized, as a greater portion of state load would be subject to the percentage renewables purchase requirement. Finally, with public power entities typically carved out of RPS requirements and markets, there may be lost opportunities to apply public finance mechanisms to reducing the cost of renewables.

4. What are the specific targets? Are the targets technology specific? How were targets determined? How accurate are assessments of availability? Are there any unique RPS design features?

Specific RPS Targets by State

The table below describes the purchase requirement in each state.

State	Purchase Requirement
AZ	0.2% in 2001, rising by 0.2%/yr to 1% in 2005, and to 1.05% in 2006, then to 1.1% from 2007 to 2012. Competitive retail suppliers are exempt until 2004.
CT	Class I or II Technologies: 5.5% in 2000, 6% in 2005, 7% in 2009 and thereafter. Class I Technologies: 0.5% in 2000 + 0.25%/yr to 1% in 2002, 6% in 2009 and thereafter. Revised law in 1999 clarifies that standard is energy based, not capacity based and allows individual suppliers to petition PUC for delay of RPS targets of up to 2 years. PUC has established that RPS shall not apply to standard offer service.
IA	105 aMW (~2% of 1999 sales) applied to IOUs
ME	30% of retail sales in 2000 and thereafter as condition of licensing. PUC will revisit RPS within 5 years after retail competition.
MA	1% of sales to end-use customers from new renewables in 2003, +0.5%/yr to 4% in 2009, and +1%/yr increase thereafter until date determined by Division of Energy Resources (DOER). Final RPS rules do not propose standard for existing renewables – DOER plans to monitor market and adopt standard if there is significant attrition. At the legislature's request, the DOER has committed to study the viability and impact of a minimum requirement for existing renewables by October 1, 2003.
NV	5% in 2003 and rises by 2% every two years until reaching 15% in 2013 and thereafter. At least 5% of the standard must come from solar (PV, thermal electric, or thermal).
NJ	Class I or II Technologies: 2.5% with no sunset. Class I Technologies: 0.5% in 2001, 1% in 2006, +0.5%/yr to 4% in 2012.
NM	Restructuring and original RPS delayed until 2007; new RPS currently under consideration: 2% by 9/03,5% by 9/05, 10% by 9/07 and thereafter.
MN	425 MW wind and 125 MW of biomass by 2002 applied to Xcel Energy; 400 MW more wind by 2012 (~4.8% of 2012 sales)
PA	For PECO, West Penn, and PP&L, 20% of residential consumers served by competitive default provider: 2% in 2001, rising 0.5%/year. For GPU, 0.2% in 2001 for 20% of customers, 40% of customers in 2002, 60% in 2003, 80% in 2004 and thereafter.
TX	Legislation establishes renewable energy capacity targets: 1280 MW by 2003 increasing to 2880 MW by 2009 (880 MW of which is existing generation). RPS rule translates capacity targets into percentage energy purchase requirements.
WI	0.5% by 2001, increasing to 2.2% by 2011 (0.6% can come from facilities installed before 1998).

Technology Specific Targets

Technology-specific targets include:

- Arizona: Solar electric must make up at least 50% of the standard in 2001-2003 and 60% in 2004-2012. Also, R&D investments can reduce RPS target by up to 10% in 2001 and 5% in 2002-2003. Solar thermal can make up to 20% of requirement, and investment in in-state solar manufacturing can reduce RPS.
- Connecticut: Distinguishes between Class I and II technologies. See answer to question 6 for Class I and II definitions.
- Nevada: At least 5% of the standard must come from solar (PV, thermal electric, or thermal).

- New Jersey: Distinguishes between Class I and II technologies. See answer to question 6 for Class I and II definitions.
- New Mexico: Proposed RPS would require that no more than 50% of the RPS be met by any single renewable resource.
- Minnesota: Specific purchase requirements for wind and biomass.

The Target Setting Process

The targets themselves are typically determined in a political setting, informed by cost and benefit estimates, but driven primarily by political viability. Targets are usually set at a level that is insufficiently high to create overly aggressive opposition to the RPS, but is high enough to ensure strong support among environmental and renewable energy stakeholders. Where the RPS includes existing renewable generation, the percentage target often begins at or near an estimate of current existing renewable generation in or serving the state. When only new generation is eligible, the target will typically begin at a very low level to ensure a reasonable development time before multiple large-scale renewable projects are needed to meet RPS targets. The percentage targets typically increase gradually to ensure incremental renewables development over time. Also impacting the target level are decisions about technology eligibility, and the costs of those technologies that are eligible. In Arizona, for the example, the RPS is primarily intended to drive solar development. Because solar is one of the most expensive forms of renewable energy, the RPS targets are low in percentage terms to ensure that rate impacts are not pronounced.

Assessments of Resource Availability

One of the critical failings of several RPS' has been that policymakers have not adequately considered rules for geographic eligibility or impacts of regional renewables in determining their RPS targets. As described above, the RPS targets in those states in which existing generation is eligible often begin at an estimate of existing in-state renewables supply, or alternatively an estimate of the amount of existing renewables supply serving the state from in- and out-of-state resources. A primary problem with this approach is that it does not consider the fact that existing renewable resources in nearby states that were not previously serving the RPS state could do so in the future. Take the case of Maine, whose RPS counts hydropower and natural gas cogeneration systems from throughout New England and eastern Canada as eligible; similar problems have arisen in New Jersey and Pennsylvania, and to a lesser extent in Connecticut.

The primary lesson here is that accurate assessments of the availability of renewable generation must consider not only that amount of existing renewable energy in the specified state, but also resource availability in nearby states and an assessment of the likelihood that those resources could be sold into the RPS state (considering transmission issues, rules for geographic eligibility, and the existence of other RPS requirements in the region that could keep such renewables "at home"). Details of geographic eligibility are critically important to consider early on in an RPS design process.

In addition, it is also critical to have a realistic assessment of potential new renewables in order to set achievable percentage target requirements. As with existing renewables, the entire region within which eligible generation can be built and delivered according to import rules (if allowed) must be considered in addition to in-state generation. An assessment of the Massachusetts or

Connecticut RPS would conclude that the standards might not be achievable at politically acceptable cost if only in-state generation were eligible. If expanded to New England or beyond, substantially more supply might be available to keep up with demand.

Unique RPS Design Features

Some of the more unique design features of the state RPS requirements that are not otherwise discussed in this paper are described below:

State	Unique Design Features
AZ	• RPS cost recovery through SBC and specifically designated charge on electricity rates. • Allows R&D investments and investments in in-state solar manufacturing to reduce RPS. • Credit multipliers (e.g. greater than 1 credit per kWh) for early solar installation, in-state projects and manufacturing, distributed solar, net metering, and utility green pricing. • Allowance of solar hot water and air conditioning in RPS.
CT	• Exempts standard offer and default service providers.
ME	• Cogeneration is an eligible resource. • Allows voluntary payment into renewable energy R&D fund to avoid license revocation if out of compliance with the RPS.
MA	• Allows some existing (biomass) generation to qualify above 5-year historic baseline of production. • Alternative compliance mechanism of 5 cent/kWh payment to MTPC in lieu of direct RPS compliance demonstration documented by possession of eligible renewable certificates. • Restrictions on eligible biomass resources. • Early compliance and banked compliance (limited to 2 years and 30% of annual obligation) allowed.
NV	• Allows solar-thermal (e.g. solar hot water) to qualify as eligible. • Details on how utility will contract with renewables in a way that is approved by the PUC, and how petitions for exemptions will be treated. Contracts are required to exceed 10 years in duration. • Each utility estimates RPS requirement one year in advance by applying percentage requirement to estimate of utility load. Utility not out of compliance as long as they deliver enough renewables to meet the estimated requirement. • Compliance banking allowed for 4 years. • Metering not required for systems under 10kW in size and for solar thermal systems.
NJ	• Hydro and waste-to-energy qualifies as a Class II technology only if located in a state that allows retail competition and meets high environmental standards.
NM	• Financial reward for utilities that go beyond their specific purchase requirement. • No single energy source can make up more than 50% of RPS requirement. • Proposed RPS contains details on cost recovery and prudence of renewable energy investments by IOUs.
PA	• Purchase requirement applies only to competitive default suppliers.
TX	• Initial RPS targets were capacity based, though PUC translated this into energy-based targets.

State	Unique Design Features
	• RPS applies to new renewable generation, but existing generation can reduce RPS requirements for supplier but cannot be traded in the REC program. • First state to develop comprehensive REC program. • Allows customer sited renewable electricity and thermal plants to qualify. • Early compliance, 3 month settlement, 2 year banking, and limited borrowing of RECs.
WI	• Attorneys General has authority to levy fines for noncompliance. • Allows credit trading for those renewables that utilities purchase beyond their specific purchase requirement. • Retail sales determined with 3-year rolling average. • First comprehensive RPS to be implemented outside of retail electricity reform process.

5. How are "renewables" defined? How is hydro handled (small, large, new, existing)? How are out-of-state purchases handled? How are existing renewables handled?

The following table highlights answers to each of the questions above. As shown, each state treats these issues in its own way with quite a lot of variability across states.

State	Resource Eligibility	Hydro Eligibility	Out-of-State Eligibility	Existing Renewables Eligibility
AZ	Solar electric (at least 50% in 2001-2003 and 60% in 2004-2012), solar hot water, in-state landfill gas, wind, biomass. R&D investments can reduce RPS target by up to 10% in 2001 and 5% in 2002-2003	None eligible	Out-of-state solar is eligible, but credit multipliers provide incentives for in-state solar; landfill gas, wind and biomass must be in-state	Eligible plants must be installed after January 1, 1997
CT	Class I: solar, wind, new sustainable biomass, landfill gas, and fuel cells Class II: licensed hydro, MSW, other biomass	None eligible in Class I In Class II, must be licensed; new and existing eligible	Eligible; likely to be covered under NE G.I.S. rules for imports into New England. Proposed legislation would expand to all NY, PJM, eastern Canada.	Eligible, except only new sustainable biomass is eligible under the Class I standard
IA	Solar, wind, methane recovery, biomass	None eligible	None eligible	None eligible
ME	Fuel cells, tidal, solar, wind, geothermal, hydro, biomass, and MSW (under 100 MW), high efficiency cogeneration of any size	All eligible	Eligible; energy must be delivered at present to the ISO-NE control area and meet load in New England, or may in any way satisfy load within the ISO-NE control area	Eligible

State	Resource Eligibility	Hydro Eligibility	Out-of-State Eligibility	Existing Renewables Eligibility
			(for generation under 5 MW); same provisions for the Maritimes control area; in future, likely to follow NE G.I.S. rules	
MA	Solar, wind, ocean thermal, wave, tidal, fuel cells using renewable fuels, landfill gas, digester gas, and low-emission advanced biomass, which is defined in detail in DOER RPS rule and includes fuel, technology, and emissions requirements; off-grid and customer-sited generation are eligible, as is co-fired biomass; DOER can add technologies after hearings	Hydro not eligible under "new" RPS	Customer-sited and off-grid generation must be located in MA; grid connected generation from out-of-state is eligible; generation from outside New England also eligible if meets certain import requirements	New renewables defined as those that begin commercial operation or represent an increase in capacity at an existing facility after December 31, 1997. DOER to study viability and impact of existing renewables RPS by 10/1/03.
MN	Wind and biomass	None eligible	First round did not have in-state requirement (in part because the state Attorneys General rejected such an approach on the grounds that it would violate the Interstate Commerce Clause), but all parties expected projects to be located in state; new 400 MW requirement by 2012 may be met with in-state or out-of-state supply on a least cost basis	None eligible
NV	Wind, solar (PV, solar thermal electric, solar thermal that offsets electric use), geothermal, and biomass energy resources that are naturally regenerated. At least 5% of each year's standard	None eligible	Eligible renewables must be located in-state or be located out of state with a dedicated transmission line (shared with only one other non-renewable	Eligible

State	Resource Eligibility	Hydro Eligibility	Out-of-State Eligibility	Existing Renewables Eligibility
	must come from solar.		generator) to an in-state utility	
NJ	Class I: solar, PV, wind, fuel cells, geothermal, wave or tidal, and methane gas from landfills or a biomass facility, provided that the biomass is cultivated and harvested in a sustainable manner (biomass is further and more specifically defined in the BPU's interim rule) Class II: hydro (<30 MW in interim rule) and resource recovery facilities in areas with retail competition	None eligible in Class I In Class II, interim rule says hydro must be 30 MW or less, unless or until NJDEP issues more specific environmental criteria Hydro must be located in areas that allow retail competition	Eligible generally if generation flowed to PJM or NY ISO control areas; Class II technologies must come from states open to retail competition	Eligible
NM	Solar, wind, geothermal, hydro, wave, biomass (agricultural or animal waste, small diameter timber, salt cedar, etc.), landfill gas, anaerobic digestion, renewably-fuelled fuel cells	All eligible, whether existing or new	Eligible only if the other state allows renewable generators located in New Mexico to sell into their RPS	Eligible
PA	Solar, wind, sustainable biomass (including LFG), ocean; PECO, West Penn and PP&L allow geothermal; GPU allows some waste coal and one MSW plant	None eligible	Eligible	Eligible
TX	Solar, wind, geothermal, hydro, wave, tidal, biomass, biomass-based waste products, landfill gas	All eligible; only new eligible for REC trading; existing hydro can offset RPS requirements of suppliers that hold title to the hydro generation	Not eligible unless dedicated transmission line into the state	Plants commissioned after 09/01/99 or < 2 MW (regardless of commissioning date) are eligible, and can trade RECs. Purchases from plants > 2MW and commissioned before 09/01/99 are eligible to satisfy

State	Resource Eligibility	Hydro Eligibility	Out-of-State Eligibility	Existing Renewables Eligibility
				the purchaser's requirement, but RECs cannot be traded
WI	Wind, solar, biomass, geothermal, tidal, fuel cells that use renewable fuel, hydro under 60 MW; eligibility may be expanded by PUC	Only hydro under 60 MW eligible; but, only 0.6% of sales can be met with facilities installed before 1998	Eligible	Eligible, but only 0.6% of sales RPS can be met with facilities installed before 1998

7. How are the conditions in the other states similar or different than those in New York? Existence of retail and wholesale competition? Existence of an SBC or other public benefit initiatives supporting renewables? Details (overlaps in eligibility; funding interaction, etc)? Renewables potential, type, renewables as percent of existing resource mix? Mandatory Environmental Disclosure? How do electricity prices compare?

Some of the information requested is provided in the table below.

State	Retail Competition	Liquid Wholesale Spot Market	SBC or Other Funds for RE?	Environmental Disclosure*	Avg Residential Electricity Rate
NY	yes	yes	yes	yes (FM, ENV)	14.0 ¢/kwh
AZ	yes	no	yes	limited (FM, ENV)	8.4 ¢/kwh
CT	yes	yes	yes	limited (FM, ENV)	10.9 ¢/kwh
IA	no	no	no	no	8.4 ¢/kwh
ME	yes	yes	no	limited (FM, ENV)	12.5 ¢/kwh
MA	yes	yes	yes	yes (FM, ENV, labor)	10.5 ¢/kwh
MN	no	no	yes	yes (FM, ENV)	7.5 ¢/kwh
NV	yes (limited)	no	no	no	7.3 ¢/kwh
NJ	yes	yes	yes	yes (FM, ENV)	10.3 ¢/kwh
NM	no	no	yes (2007 start)	delayed with restructuring (FM, ENV proposed)	8.4 ¢/kwh

State	Retail Competition	Liquid Wholesale Spot Market	SBC or Other Funds for RE?	Environmental Disclosure*	Avg Residential Electricity Rate
PA	yes	yes	yes	limited (FM)	9.5 ¢/kwh
TX	yes	yes	no	yes (FM, ENV)	8.0 ¢/kwh
WI	no	no	yes	no	7.5 ¢/kwh

* FM = fuel mix disclosure; ENV = emissions disclosure; limited = some restrictions to disclosure apply

As shown above, many of the states that have implemented RPS requirements or other renewable energy purchase mandates share common characteristics with New York.

- <u>Retail Competition.</u> 8 out of 12 states have opened their market to retail competition, as has New York. Retail competition has been delayed in New Mexico, in large part due to California's negative experience with competition, while Wisconsin, Iowa, and Minnesota have never fully committed to retail competition, instead adopting a gradual "wait-and-see" approach to restructuring.
- <u>Wholesale Competition.</u> We assume here that the most relevant aspect of wholesale competition is the existence of wholesale spot energy (and ancillary services) markets. 6 out of 12 states have liquid wholesale spot markets with visible process similar to New York, while other states have access to more limited spot market transactions.
- <u>Renewable Energy Funds.</u> 8 out of 12 states have established renewable energy funds in addition to their RPS requirements to help support renewable energy. Further details on these funds is provided below.
- <u>Environmental Disclosure.</u> 9 of 12 states have some form of fuel source and/or environmental disclosure. Several of these states' disclosure rules are more limited than those in New York, however.
- <u>Electricity Prices.</u> One area of difference among these states is electricity prices. Those states that have implemented the RPS have average residential electricity prices that range from a low of 7.3 cents/kWh to a high of 12.5 cents/kWh (according to EIA 2000 data). New York's average residential electricity rate is higher than these, at 14.0 cents/kWh.

With respect to the renewable energy funds specifically, and how they will interact with the RPS' in each state:

- <u>Arizona:</u> This state's SBC fund will be used primarily to directly help fund the cost of the solar-based RPS, so will not have an incremental effect on renewables development. The charges being collected by the utilities are used to cover their RPS compliance costs.
- <u>Connecticut:</u> The Connecticut Clean Energy Fund has stated that it will help ensure the success of the RPS by funding RPS-eligible projects, though some of its funding is going towards investments that would not be eligible under the RPS or that would not be low-cost compliance options under the RPS.
- <u>Massachusetts:</u> It's not clear whether the Massachusetts Renewable Energy Trust (MRET) will allow funded projects to be used for RPS compliance. In a recent solicitation for pre-

development financing, MRET required funded projects to offer their output into Massachusetts' green power market, implying that it might not be RPS-eligible. Much of MRET's funding is going towards investments that would not be eligible under the RPS or that would not be low-cost compliance options under the RPS. While there is no guidance in enabling legislation suggesting the RPS-SBS interaction, recent MRET actions suggest that SBC-funded activities are intended to result in activity incremental to the RPS.

- Minnesota: Minnesota has a renewable energy fund, funded through a utility radioactive waste storage settlement. The fund is mostly focused on projects that would otherwise not be competitive under the Xcel renewable energy purchase mandate.
- New Jersey: The interim RPS rule states that, for now, SBC-funded projects are eligible to satisfy the RPS, though some of its funding is going towards investments that would not be low-cost compliance options under the RPS.
- New Mexico: New Mexico's SBC fund has been delayed until 2007, and is focused on renewable generation installed by public-sector organizations. Assuming the RPS is intact in 2007, it would appear that the SBC will be funding investments that would not otherwise receive strong support under the RPS.
- Pennsylvania: Pennsylvania's funds allow funded projects to sell to both in-state and out-of-state (i.e., NJ) RPS markets.
- Wisconsin: Wisconsin's SBC program is focused almost exclusively on demand-side applications for renewable energy, knowing that supply-side projects will be supported by the RPS.

The table below compares the amount of existing renewable generation located in these states on a MWh and percentage basis to that in New York.

State	Solar, wind, biomass, geo, LFG (MWh)	Solar, wind, biomass, geo, LFG (% retail sales)	Solar, wind, biomass, geo, LFG, MSW, hydro (MWh)	Solar, wind, biomass, geo., LFG, MSW, hydro (% retail sales)
NY	1,127,890	1%	24,544,797	20%
AZ	108,905	<1%	8,648,758	14%
CT	264,951	1%	2,540,440	8%
IA	725,600	2%	1,588,528	4%
ME	2,776,472	18%	6,488,932	42%
MA	224,952	1%	2,952,037	6%
MN	1,297,164	2%	2,961,421	5%
NV	1,347,314	5%	3,821,783	14%
NJ	258,931	<1%	1,407,518	2%
NM	15,001	<1%	227,395	1%
PA	985,799	1%	4,389,668	4%
TX	3,557,213	1%	4,539,737	1%
WI	1,199,033	2%	3,034,862	5%

* Table uses EIA data, REPIS and other data sources to approximate 2001 supply.

As shown in the table, the combined amount of wind, biomass, landfill gas, geothermal and solar in New York is very consistent with that of other states that have RPS requirements. Seven of these other states have approximately the same or less of these resources than New York, while 5 states have more of these resources than New York. When one adds hydropower and MSW, New York rises to the top of the list, with only Maine having a greater proportion of renewables.

Presumably, NYSERDA's interest in resource potential is relative to the required percentages, and focused on whether or not the RPS is binding, and will lead to new renewables, without resulting in shortages or high cost impacts. In terms of future renewable resource potential, no single source of data is available with which to compare the relative endowment of each state. Furthermore, quantifying the renewable resource potential is a complex and time-consuming analysis if you want to avoid misleading results. Little of the data is found in a readily accessible form and much of it is suspect. Potential import eligibility may render state-bounded resource assessments of little direct value. The important characteristic is whether future resources appear to be plentiful enough within geographic reach so that the increasing percentage is binding but not overly challenging to meet. Short of an extensive analysis of each state (beyond the current scope and budget), our understanding of new renewable resource availability in each of these regions leads us to the following findings:

- Arizona: excellent solar resources, limited LFG opportunities, and moderate wind resources would appear to be sufficient to ensure RPS compliance.
- Connecticut: Some concerns have been expressed as to the availability of resources in both the long-and short-term. Whether these concerns are well founded has much to do with the lack of a strong RPS motivating investment, the lack of credit-worthy buyers, and the uncertainty about the ability to cost-effectively import resources from outside New England under the fledgling NEPOOL G.I.S. system. However, we do believe that the Class 1 RPS requirement, if limited primarily to New England-based resources, would lead to shortage. This concern is in part responsible for current efforts in the legislature to allow generation RECs from NY, PJM or eastern Canada to be used for compliance.
- Iowa has easily had adequate resources for compliance, mostly wind.
- Maine does not have an explicit requirement for any new resources, and the standard is set well below the available inventory of eligible resources, so availability will not be an issue.
- Massachusetts: Like Connecticut, there are some concerns as to the availability of resources in both the long-and short-term. Siting new generation has proven to be particularly difficult within the region. And like Connecticut, the near-term shortages may result from lack of credit-worthy buyers, and the uncertainty about the ability to cost-effectively import resources from outside New England under the fledgling NEPOOL G.I.S. system. A combination of New England generation and imports, the potential for large off-shore wind development (speculative at this juncture), and an alternative financial compliance mechanism should keep the RPS from failing due to lack of future supply.
- Minnesota would appear to have adequate resources for compliance, mostly wind.
- Nevada has strong geothermal, solar, and adequate wind resources to meet its requirements.

- New Jersey can rely on adequate Class 1 renewable resource potential in Pennsylvania, West Virginia, and New York to meet its Class 1 RPS requirement.
- New Mexico has a strong solar resource and enough wind to satisfy its requirement in the foreseeable future.
- Pennsylvania has a minute requirement and more than enough eligible resources to supply it.
- Texas has awesome wind potential that dwarfs the RPS percentages.
- Wisconsin has modest wind and biomass resources, but the surrounding states (IA, etc) have substantial wind resources that are sufficient to support the requirement.

8. How are imports and exports handled for both renewables and non-renewable? Please be as specific as possible.

Treatment of imports in RPS or purchase mandate requirements is summarized in the table below. Exports are typically not addressed in RPS rules - the only situation in which exports are relevant is in the case of export of commodity energy from a renewable generator under a tradable certificates regime. In this case, the RECs could still be used for in-region compliance purposes, e.g. in Texas and New England. In all other cases, if electricity is exported, so are the attributes. In practice, it is unlikely that a renewable energy generator would ever sell in a bilateral contract its energy, without attributes, across market boundaries.

Likewise, cross-border transactions of non-renewable attributes do not receive mention in RPS rules. Energy is transacted across market boundaries all the time, but in the absence of attribute requirements – RPS or other purchase mandates, source/emissions disclosure, or an emission performance standard (EPS) – there is little concern with associating particular generation sources with cross-border energy transactions.

Exports do receive some consideration in rules governing the accounting and verification for environmental disclosure (e.g. NY) or disclosure and EPS (New England's G.I.S. system), and in these cases only to prevent double use of attributes. Where treatment of exports is defined, it is generally only of interest from an RPS perspective to the extent that it impacts the eligibility of imports in some other state (see discussion of compatibility in table below).

State	Treatment of Imports
AZ	Out-of-state solar eligible through tradable renewable credits. In-state gets 50% more credit than out-of-state solar and out-of-state requires demonstration of transmission of energy to Arizona consumers. Imports therefore unlikely to be a factor.
CT	Currently governed by NEPOOL G.I.S. rules, which require imports via "external unit contracts" from neighboring control areas (e.g. bilateral bundled transactions matching unit production in each hour, transmission reservation, NERC tag). Rules could be altered in the future for imports from a neighboring control area with a compatible information system. All exports from New England must have associated certificates. Proposed legislation would expand to all NY, PJM, Eastern Canada through tradable RECs tracked by local accounting and verification system sanctioned by CT.

State	Treatment of Imports
IA	None eligible
ME	Currently, renewable energy imports must be delivered to NE or Maritimes to meet load (if for generation < 5MW, meet load in any way in NE). This is likely to shift to being governed by the NEPOOL G.I.S. rules, which require imports via "external unit contracts" from neighboring control areas (e.g. bilateral bundled transactions matching unit production in each hour, transmission reservation, NERC tag). Rules could be altered in the future for imports from a neighboring control area with a compatible information system. All exports from New England must have associated certificates.
MA	Currently governed by NEPOOL G.I.S. rules, which require imports via "external unit contracts" from neighboring control areas (e.g. bilateral bundled transactions matching unit production in each hour, transmission reservation, NERC tag). Rules could be altered in the future for imports from a neighboring control area with a compatible information system. All exports from New England must have associated certificates.
MN	First round of the purchase mandate did not have an in-state *requirement*, in part because the state Attorneys General rejected such an approach on the grounds that it would violate the Interstate Commerce Clause, but all parties expected and effectively agreed that the wind projects would be located in state. The new 400 MW requirement by 2012 may be met with in-state or out-of-state supply on a least cost basis. We assume it would require a transmission path if located out-of-state.
NV	Eligible renewables must be located in-state or be located out of state with a dedicated transmission line (shared with only one other non-renewable generator) to an in-state utility
NJ	Eligible generally if generation flowed to PJM or NY ISO control areas. This implies that bundled generation and attributes from outside PJM or NY could be considered eligible only if energy is delivered to PJM or NY.
NM	Imports are eligible only if a PRC-certified source, and the other state allows renewable generators located in New Mexico to sell into their RPS. No specific mechanism has been defined. We presume that attribute imports would require that energy be delivered to New Mexico.
PA	Eligible, but details unspecified in PA. PJM is working on a tracking system that may ultimately address and create specific mechanisms for imports.
TX	Not eligible unless energy is transmitted via dedicated transmission line into the state; even then, imported renewables do not count towards the 2000 MW state goal.
WI	RECs are only provided to a Wisconsin utility to the extent that they have excess renewables. Imports therefore must be accomplished by wheeling energy (wth attributes) into Wisconsin, after which excess can be traded.

9. Do all states that have adopted an RPS also have an energy credit trading system? How are these systems working out?

A renewable energy credit trading system may be a desirable, but is certainly not a necessary aspect of a state RPS. A number of states neither have a REC program nor are developing one.

The status of each state's approach to tracking RPS compliance is provided below.

State	Tracking System (RECs, contract path, etc.)
AZ	The ACC allows utilities to use credits to bank or trade renewable generation. This is not a comprehensive system, however, and no central REC registry or system exists or is planned. Rather, in the utilities' compliance filings they may document the use of these credits to bank or trade renewable energy. Because there are few utilities on which the RPS falls, the ACC has so far been able to manage with this form of RECs tracking compliance and has no expectation of creating a more complex system. There has been a limited amount of credit trading in LFG and solar credits, and parties appear to believe that the system is working well.
CT	RPS historically based on contract-path tracking, though legislation allows suppliers to participate in a credit-trading program. With development of NE G.I.S., state will use generation certificates system in the future to document RPS compliance. No experience with this system yet exists. Proposed legislation allows for generation eligibility over a broader geographic region through the use of RECs verified through a PUC-sanctioned accounting system.
IA	Iowa used a contract-path tracking system to ensure that its previous purchase mandate would be met.
ME	Maine disallowed the use of RECs in its original RPS rules to maintain consistency with the regional disclosure tracking systems in discussion at the time. With development of NE G.I.S., state will use the generation certificates system in future to document RPS compliance. No experience with this system yet exists.
MA	With development of NE G.I.S., Massachusetts will use the generation certificates system in future to document RPS compliance. No experience with this system yet exists.
MN	Minnesota has used a contract-path tracking system to ensure that its purchase requirement is met.
NV	Legislation allows credits, but the PUC rule does not implement a comprehensive credit trading system.
NJ	Though the RPS legislation indicates that electric suppliers may satisfy the RPS by participating in a renewable energy credit-trading program approved by the Board of Public Utilities (BPU), the interim RPS rule does not establish such a system. The Mid-Atlantic stakeholders are meeting with PJM to discuss the development of tracking systems for the region, but there is some resistance towards moving towards and credit or certificates-based system. In the meantime, RPS compliance is being verified on a contract-path basis. It is anticipated that the final rule will support a credit-trading system.
NM	New Mexico's RPS proposal allows public utilities to apply to the Commission for approval of "trading credits" as a means of satisfying the RPS.
PA	Pennsylvania's renewable purchase requirements lack many details, but presumably use a contract-path tracking mechanism. The Mid-Atlantic stakeholders are meeting to discuss the development of tracking systems for the region, but there is some resistance towards moving towards and credit or certificates-based system.
TX	Texas is the first state to establish a credit-trading program. ERCOT ISO was selected as the program administrator (see www.texasrenewables.com for ERCOT's REC program information). Note that ERCOT does not operate an exchange, but rather a registration and tracking system. REC trades take place through private brokers, or RECs are bundled with commodity energy and sold through long-term contracts. The central database and registry system is administered by the ERCOT ISO, and the software was developed by APX. The system began operations in mid-2001, so little experience yet exists with its use. However,

State	Tracking System (RECs, contract path, etc.)
	the system has reportedly been running smoothly, and meeting the needs of generators and retail suppliers at low cost. We also understand that the ERCOT ISO has found the system to be very easy to administer.
WI	Wisconsin has developed a limited REC program to use for their RPS. The state has not yet developed a comprehensive, central REC registry or database system. Instead, they allow utilities that exceed their RPS requirements to apply for RECs from the utility commission for the amount of the exceedance. These credits can then be used in future compliance periods or be sold to another utility that required the credits for their own compliance. The PUC RPS rule indicates that the Commission will track these RECs through a database system that is contracted out to a program administrator, and an RFP is likely to be released with a week to solicit proposals for such a program administrator. Some credit trades have already taken place, and the program administrator is expected to have a formal system to track these RECs by the end of the year. The system, as it exists today, appears to be working reasonably well.

As shown above, only the state of Texas has developed and implemented a comprehensive REC system to date. That system began operations in mid-2001 with development costs of ~$500,000. All reports suggest that the system is operating smoothly, and the ERCOT ISO reports that administration of the system has been simple and not costly.

Wisconsin and Arizona have developed far less comprehensive REC systems that reflect the fact that their RPS requirements are currently imposed on a limited number of regulated electric utilities. In such an environment, RECs have less value as a tracking system and the more limited use of RECs in these states appears to be serving the needs of these two states adequately. We note, however, that these systems have not been operating for long so detailed conclusions are not yet available.

The New England states are developing and will implement within the next few months a more comprehensive certificates tracking system that will cover both renewable and non-renewable generation. With a development cost of ~$2.5 million, this system will be used to meet disclosure, RPS, EPS and other requirements in each of the New England states. New England has adopted this approach because the contract-path accounting approach originally envisioned was deemed by a broad multi-stakeholder consensus to be both unwieldy and incapable of supporting multiple policies – disclosure, EPS and RPS – without creating significant potential for double counting and other policy conflicts.

10. Can distributed generation from renewable energy be made eligible? For example, if utility companies were allowed to include distributed generation resources in their renewables mix (regardless of who paid for the equipment), they may be more inclined to interconnect these resources instead of viewing DG as a revenue loss.

State experience with RPS policies shows that renewable DG can be made eligible under an RPS, with a number of variations in how this might be designed. These variations include:

- whether renewable DG is eligible.

- what kinds of renewable DG are eligible,
- what fraction of their generation output or offset is eligible to meet RPS requirements, and
- who gets credit for the output.

A summary of how the various states treat renewable DG is provided below. We might note, however, that in most cases making renewable DG eligible is unlikely to create strong incentives for utilities to facilitate the interconnection of these systems. After all, renewable DG will rarely be the cheapest compliance option under an RPS.

State	Tracking System (RECs, contract path, etc.)
AZ	Customer-sited grid-connected and off-grid solar electric systems are eligible. Meters that are read at least annually are required. Credit for net-metered or utility-leased solar systems are provided to the LSE in whose service territory the system is located. Credit is also provided to the LSE for grid connected or off grid systems in which the LSE has contributed 10% of the total installed cost or has financed at least 80% of the total installed cost of the system. Solar hot water and solar air conditioning are also eligible, and credit is given to the LSE if the LSE contributed to the installation of the system.
CT	The Connecticut RPS legislation and regulations do not include provisions on renewable DG units. Customer-sited renewable plants that are used for self-generation purposes are presumably not eligible under the Connecticut RPS.
IA	Iowa's renewable purchase requirement did not allow customer-sited renewable DG used for on-site power needs to be eligible.
ME	Customer-sited renewable DG used for on-site power needs are not eligible.
MA	Off-grid renewable generation qualifies under the RPS if located in Massachusetts. Similarly, customer-sited generation that is used for on-site power needs also qualifies for the RPS if located in Massachusetts. In either case, unlike Arizona, the system owner receives the "credit" for the LSE in which the system is located.
MN	Minnesota's renewable purchase requirement is unclear on this point, but customer-sited renewable DG used for on-site power needs are presumably not eligible.
NV	The excess kWh generated by a net-metered renewable system and fed back to the LSE may be used to meet that LSE's compliance obligations under the RPS. Any equivalent kWh attributable to the LSE from solar thermal systems may also be used to meet compliance obligations, as long as the solar thermal system is SRCC certified and is used in conjunction with an electric water heater. For the LSE to claim this equivalent generation, however, it must have subsidized the solar thermal system in some way. Metering is required for systems greater than 10kW in size.
NJ	Aggregate generation from small renewable energy systems, 100 kW or less, may be used to meet the RPS, provided that the generators or customer-generators can document the level of generation by appropriate metering. This includes generation used on site under net metering, though the generator must be located in New Jersey. Credit for these systems under the RPS goes to the system owners, unless otherwise allocated.
NM	Not addressed in proposed RPS.
PA	Pennsylvania's renewable purchase requirements are unclear on this point, but customer-sited renewable DG used for on-site power needs are presumably not eligible.
TX	Renewable energy sources that offset (but do not produce) electricity (e.g., solar hot water, geothermal heat pumps), and off-grid and customer-sited projects (e.g., solar) are eligible under the RPS rule. Credit for these systems is to be provided to the system owner. The PUC and ERCOT ISO have not yet developed a mechanism for these systems to obtain and sell credits, however.

State	Tracking System (RECs, contract path, etc.)
WI	Wisconsin's RPS legislation and regulations are unclear on this point, but customer-sited renewable DG used for on-site power needs are presumably not eligible.

We find that 5 of the 12 states allow certain forms of customer-sited renewable DG that is used for on-site use to qualify under their RPS requirements. In three of these cases, MA, TX, NJ, the credit for these systems goes to the system owner. In the case of Nevada, the LSE receives limited credit for these systems. In Arizona, credit for customer-sited systems is almost always offered to the LSE in whose service territory the system is located.

Fairness would seem to dictate that credit be given to the generation owner. We find the suggestion that utilities would be more welcoming of DG resources if allowed to abscond with the credit to be tenuous at best. The only argument we can find for allowing the LSE to capture the benefit is that particularly in a solar-only RPS (like AZ), the administrative details of providing credit to individual customers would be daunting. With the prospect in NY of distributed wind, fuel cells and biomass digesters, the utility capturing the value of credit it has not paid for would be more of an impediment than an incentive.

11. When will the evidence for success or failure of RPS programs by the various states become fully available?

There is no way to identify a specific date on which the RPS will have been deemed a policy failure or a policy success. In fact, early experience in the U.S. already shows that the RPS can be an incredibly effective policy tool or can be an abject failure depending on its design. Experience does suggest that through incorporating lessons learned, RPS policies initially deemed a failure can be resurrected (which appears to be happening in Connecticut through proposed legislation receiving broad support).

Evidence of the likely success or failure of an RPS is often clear as early as when the legislation is signed or the RPS regulations are promulgated. In Maine, for example, the basic design of the RPS made it clear early on that it would have minimal effect, while the strong design of the RPS in Texas by the PUC provided a good indication of the success that has followed.

In other states, it can take several years before success or failure can be claimed. The Maine and Connecticut RPS, now after a couple years of experience, have shown themselves to be failures (ate least so far – the Connecticut RPS may be redesigned in a positive way). The Texas and Wisconsin policies, on the other hand, are clear successes with less than two years of experience on which to base conclusions.

States whose RPS policies are just coming into implementation – e.g., Massachusetts, Nevada – will likely need 1-3 years of experience before preliminary analysis is possible. Other states may take even longer to evaluate. The New Jersey RPS, for example, is unlikely to be binding (i.e., require incremental new renewable productions) until 2006/2007 (although the prospect of the RPS combined with SBC incentives may have led to the merchant renewables glut that cause it to not be binding today). In this case, a more complete evaluation of that policy may have to wait until 2008.

12. What unique state characteristics are likely determinants of success of an RPS?

To answer this question first requires that we define success. We suggest that a successful RPS will have some combination of the following characteristics:

- New Development: New renewables are getting financed and built.
- Full Compliance: The RPS is being complied with in general, perhaps a bit ahead of schedule.
- Reasonable and Stable Costs: There is a definite price premium that reflects costs more than shortage. This corresponds with a situation in which the market price for renewables is not overly volatile, prone to REC price spikes and/or crashes, and costs are low enough so that there is minimal political heat and high enough to provide necessary revenues to encourage new development;

Other potentially important criteria for success, depending on state policy goals, include:

- Diversity in Supply: The mandate results in a diversity of supply.
- Generation Location: The location of generation is consistent state policy objectives.

Determinants of success can be sorted into four categories, including: market context, RPS design, resource availability, and policy and politics.

Category	Necessary to ensure success	Helpful but not essential
Market Context	• utilities or other credit-worthy entities are present and willing to enter into long-term contracts with renewable generators • if applied in a competitive retail market, a competitive wholesale market exists	
RPS Design	• broad applicability (not exempting SO/DS) • RPS percentage is binding but not overly so • teeth (penalties, alternative compliance, threat to license…) • compliance flexibility (banking, etc.) • how eligibility is handled with respect to plant vintage (at the outset), location & imports, etc.	• low-cost compliance method (like tradable credits) especially valuable in retail competition context
Resource Availability	• renewables are reasonably cost-effective and feasible to site and build in reasonable time frame • the status of markets in surrounding	• merchant renewables available to prove the concept and demonstrate feasibility

	areas is taken into account in setting percentage	
Policy & Politics	• policy stability over sufficiently long period to allow financing; low regulatory or legislative risk exposure to changes in rules • to the extent applied to regulated utilities, utility regulators keep an eye on compliance prudence, cost recovery, and contracting issues	

13. What are the RPS design criteria that will determine success in New York State?

Referring to the table in the previous response, one can see that some elements of the New York market environment are amendable to the establishment of an effective RPS. For example:

- While utilities have divested, they currently serve as provider of last resort and therefore (in a well-designed RPS) can be positioned as credit-worthy renewables buyers.
- A competitive wholesale market structure is in place.
- A low-cost compliance method - conversion transactions – has already been adopted by the PSC to support environmental disclosure. While not providing all the benefits of tradable renewable credits, this is far superior to relying exclusively on a pure contract path approach.
- A cost-effective renewable resource base is present, siting and permitting have proven to be feasible, so that renewables can be built in a reasonable timeframe to meet RPS demand.
- Some merchant renewables are already present in the market, providing a source of renewables for startup ESCOs that are unable offer credit-worthy long-term contracts to renewable generators.
- In several surrounding markets, RPS policies have been adopted. This may in part stem the potential flooding of the market from existing and new renewable generators in near-by states (the degree to which this is a threat depends on design details) for some technology types. In addition, most surrounding market areas – Ontario, New England, and PJM (Quebec being a glaring omission) – have either adopted or are working on developing accounting and verification systems that would help simplify potential accounting treatment of imports and exports.

So, other than the establishment of an RPS and the design criteria themselves, there are few apparent impediments to an effective RPS. The PSC would clearly need to consider how to govern the RPS procurement and contracting obligations of the utility providers of last resort to ensure that these sizable players in the market enter into long-term contracts with renewable generators. The PSC would also need to consider negotiating with neighboring market areas and making necessary adjustments to ensure that its tracking and verification information system was deemed compatible with neighboring systems to provide an easy and credible way of accounting for imports/exports where applicable.

The RPS design criteria or details that will determine success for a New York RPS depend heavily on the policy's objectives. Since we have not been presented with any specific objectives of a New York RPS, let us suggest some common objectives that have justified RPS policies elsewhere and/or that might be fitting for New York. From the previous question, we have defined success as new renewables development, full compliance, and reasonable and sable costs. These are important, but more specific objectives are also required to define eligibility and other RPS design details. These might include:

- Maintain the historical contribution of renewables in the region (and their associated benefits), providing a market for at least the most cost-effective existing resources that may otherwise be unable to compete in a commodity market.
- Increase the contribution of renewables to the regional mix.
- Gain a combination of local (smog, toxics, PM), regional (acid rain), and global environmental benefits as well as local economic development and resource diversity benefits.
- Provide a long-term stable market for renewables that supports their addition at the lowest cost possible and helps lower the long-term cost of the associated technologies.
- Maintain a retail rate impact of, say, less than two percent of the total average New York electricity bill. This might support an RPS of over 10% new renewables at 2.5-2.8¢ premium if there were no feedback on lower fuel and spot electricity prices. The cost impact would be much lower if the feedback effect is considered.

Design details that might be included in an RPS to meet these objectives include:

- **Technology or vintage bands.** In a situation like that in New York, where there is a significant amount of existing renewables in the historic mix, reasonable options seem to be (a) a Massachusetts-style 2-tier system[3] with new/existing tiers, or (b) a CT/NJ-style tier system with Class I for increasing the new and most beneficial technologies, coupled with a requirement for a fixed percentage of either Class I or II resources (where Class II includes most of the technology types in existence before restructuring, and Class I includes wind, solar, landfill gas, and certain types of biomass that are particularly desirable going forward). Either system can be designed to protect the historic contribution while subjecting individual projects to competition among themselves and while also asserting competitive pressure from new or Class I technologies to avoid unmerited windfalls. If policymakers felt that existing renewable projects in New York do not require additional incentives, or that an RPS is an ineffective way of delivering those incentives, the state might also consider a single-band RPS focused on only plants build after a certain date (e.g., 2001). Such systems have operated effectively in other areas.

[3] MA legislation suggested a 2-tier approach; so far, the existing tier is still being studied and has not been implemented.

- **Applicability**. The RPS should apply to all utility and ESCO sales at retail (with the possible exception of publicly owned utilities) - no exemptions should be given to the provider of last resort.
- **Percentage.** Under either tiered approach, New York should consider setting the existing/Class II percentage at or about the historical percentage contribution, and setting the increasing new/Class I percentage subject to the cost and resource availability criteria. Based on our knowledge of the New York market and the resource availability/supply curve, the new/Class I requirement could ramp up from something like ½ to 1% at first to as high as 10% of sales and still have a good chance of meeting the 2% total bill rate impact indicated above, if the federal production tax credit continues at a similar size and with current or broader eligibility.
- **Duration and stability.**
  - The ramp up would need to extend for at least 5 to 10 years, and generators and investors must be assured that the percentage will never decrease (or not for at least 10 years after the standard stops increasing, until financing is paid off).
  - The PSC could require that utility POLR providers enter into long-term contracts, subject to prudence review, and those providers should be assured of recovering their prudently incurred costs. A requirement for ESCOs over a certain minimum size to file compliance plans (either always, or only once the ESCO failed to meet the requirement) may also aid market stability and encourage contracting in a manner that will allow project financing.
- **Eligibility – resources.** Technology and resource eligibility decisions should be tightly tied to objectives, particularly environmental impacts. Desire for diversity among renewables might also affect a decision on resource bands. A reasonable Class II-type requirement for New York might mimic the Connecticut and New Jersey definitions, focusing mostly on hydro (or some subset thereof justified by environmental criteria), existing direct combustion biomass, and perhaps waste-to-energy. A reasonable Class I-type eligibility might include wind, solar PV and thermal-electric, ocean (tidal, wave, OTEC), geothermal, and some forms of biomass with desirable characteristics in technology, fuel, sustainability and/or emission characteristics[4]. Class 1 or new plants might also be limited to those built after a certain date, with candidate dates including after the advent of restructuring or after the establishment of the RPS. Plants that could co-fire biomass fuels might be included, but present a tradeoff of lower cost per kWh versus a lack of long-term infrastructure (so that the renewables could decrease if an RPS is terminated far more easily than for dedicated renewable energy generators). One way to approach this tradeoff might be to limit the proportion that could be used for compliance from co-firing in order to assure a significant fraction of new capacity.
  - A mechanism to support eligible DG is nice but not essential to success. However, it may provide reliability benefits that justify its inclusion.
- **Eligibility – location.** Location of eligible plants is driven heavily by the objectives themselves, and constrained in part by other factors, in particular by environmental disclosure.

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[4] Clarity in defining these characteristics is absolutely critical here. Massachusetts suffered greatly and still faces a challenge over its rules designed to meet a poorly worded legislative mandate; and Connecticut and New Jersey continue to struggle with and revise their definitions, particularly "sustainable" biomass.

  - For an existing or Class II requirement, to maintain historical benefits would suggest that displacement of New York generation would be required. For out of state generation to meet this requirement, a strict delivered energy eligibility approach would seem necessary (with energy imported matching production in each hour) to prevent flooding the market with out-of-state hydro while achieving nothing. To avoid flooding the market with imports in a manner that would not create the desired diversity benefits, the PSC might consider limiting generation like NJ did to locations where retail choice is allowed. In practice, the presence of very large government-utility-owned hydro – in NY, Ontario and Quebec – makes this a touchy and controversial subject worthy of more thought than this assignment can justify. As much of the larger hydro is economic without the benefit of an RPS, the PSC might also consider a new-only RPS, or limit Class II to small hydro (or low-impact-certified hydro), to sidestep this potential problem.
  - For new/Class I resources, the objective of creating incremental local, regional, and global benefits means that displacement of New York generation may be useful but is not absolutely required if, for instance, upwind generation was displaced in a manner that led to acid rain and smog benefits for New Yorkers. The presence of environmental disclosure suggests that compliance could be accomplished using renewable energy imported with attributes[5] and verified under the PSC's tracking methods for disclosure, OR supplemental tradable renewable energy credits from defined upwind states, outside the disclosure accounting system. **[The likely merger of NYISO with ISO New England complicates matters here and deserves further consideration to accommodate.]**
- **Product rather than company basis.** It would be misleading to customers if energy sold as "green", for which a premium was paid by customers, was also used to meet a legal mandate (so that it would be generated with or without their purchase). Many RPS mandates, and those that we feel are best designed, have adopted a product-basis (e.g., Texas and Massachusetts), meaning that each offering (or each customer) must be provided with the minimum renewables percentage under the RPS.
- **Compliance flexibility.** Achieving low cost compliance and price stability in the renewables market dictates that features be added to assure reasonable compliance flexibility. We would recommend a limited degree of banking of compliance[6], and some limited (perhaps 3 month) make-up period.
- **Teeth to ensure compliance.** Financial penalties for non-compliance that include a multiple of the cost of a renewable attribute will help assure compliance. Well-defined threats to an ESCO's license (or eligibility) to sell at retail for repeat offenders should also be considered.

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[5] Delivered energy eligibility, relaxed delivery, retail or wholesale matching – see upcoming import/export white paper for more on these terms.

[6] Compliance banking differs from banking TRCs. By banking compliance, the carrying of renewables over time does not interfere with environmental disclosure. Massachusetts took this approach. Care must be taken to prevent resources sold as "green" in one year being banked for RPS compliance in following years, which would mislead green power customers. This can be accomplished by outright prohibitions, limitations on the amount that can be carried forward, etc.

- **Political acceptability.** Safety valves can increase political acceptance of the policy. The most important might be a price cap or alternative compliance method (payment to NYSERDA in lieu of renewables purchase). It might start at something like 5¢/kwh (this translates to a tiny rate impact when the RPS percentage is small) and be adjusted on occasion, with warning sufficient to not strand investments, to a level above the expected RPS compliance cost for the foreseeable future. The RPS percentage ramp-up might be slowed from an initial schedule once/if the Federal PTC is not is extended.

14. Expand the discussion on the jurisdictional requirements for the PSC to implement/design an effective RPS.

If the PSC wishes to explore implementing an RPS in lieu of legislative action to establish an RPS and absent future direct legislative instruction, it will need to first assess the degree to which (a) it has both the necessary jurisdiction and authority to both establish and enforce an RPS, and (b) it is willing to exercise that authority to implement an RPS. While the PSC staff will be best positioned to assess the answer to the first question, and the commission itself the second, here we provide a road map for considering these questions.

There is little point in the PSC trying to establish an RPS unless it has the prospect of being an effective policy capable of achieving its objectives. Such effectiveness would seem to draw from three categories of issues: jurisdiction, authority, and enforcement. While a thorough legislative and regulatory analysis is beyond the scope of this memo, a cursory review of the Public Service Law provides some guidance.

Ability to Implement an RPS through Regulatory Action
<u>Jurisdiction:</u> As pointed out elsewhere in this memo, an effective RPS in a competitive retail market must apply all those selling at retail within the state: at very least to all of the retail offerings of all of the utility/default/standard offer supply as well as to competitive ESCOs. Applicability to public power entities is would be ideal, but is not essential, and we do not see it as required for success. It appears that the applicable jurisdiction derives from Public Utilities Law Article 1 § 5. 1. b., which states that PSC jurisdiction applies "*To the manufacture, conveying, transportation, sale or distribution of gas (natural or manufactured or mixture of both) and electricity for light, heat or power, to gas plants and to electric plants and to the persons or corporations owning, leasing or operating the same*." Thus, the PSC has necessary jurisdiction over both utilities and ESCOs. Through its restructuring settlements, the PSC has already asserted its jurisdiction over the ESCOs that the settlements allowed into the market.

<u>Authority:</u> An effective RPS implemented through regulation would need to be targeted at a clearly defined set of objectives in a manner that aligns with existing statutory authority. Authority must be evaluated for both utilities and for ESCOs. In general, there are two potential sources of authority. The first is the standard authority granted to regulatory commissions consistent with their ratemaking and cost-recovery authority over utilities (this clearly does not apply to ESCOs). So one question to evaluate is whether such authority can be interpreted broadly enough to support an RPS. The second would be the existence of any specific legislation that grants a regulatory commission authority over renewables. For example, in

California, specific existing legislative language would support the PUC implementing a renewables mandate even if the legislature does not adopt one.

In the first category, the Public Service Law lays out some general authority that might be interpreted to support RPS authority in Article 1 § 5. 2. "*The commission shall encourage all persons and corporations subject to its jurisdiction to formulate and carry out* ***long-range programs****, individually or cooperatively, for the performance of their public service responsibilities with economy, efficiency, and care for the public safety, the* ***preservation of environmental values and the conservation of natural resources***." (emphasis added). In the second category, there is also language pertaining somewhat more directly to alternate energy, which might also provide a basis for authority to implement an RPS. Article 4, § 66-c. 1 (Conservation of energy) states: "*It is hereby declared to be the policy of this state that it is in the public interest* ***to encourage****, at rates just and reasonable to electric and steam corporation ratepayers,* ***the development of alternate energy production facilities, co-generation facilities and small hydro facilities*** *in order to* ***conserve our finite and expensive energy resources*** *and to provide for their most efficient utilization when such facilities are needed to fulfill the energy, capacity or other electric system needs of this state, as determined by the most recent state energy plan. In furtherance of this declared policy****, the commission shall encourage the participation of utilities in co-generation, small hydro and alternate energy production facilities either directly*** *or through subsidiaries formed pursuant to the provisions of subdivisions three and four of this section. In addition, the commission shall require any electric corporation or steam corporation (a) to enter into long-term contracts to purchase or wheel electricity or useful thermal energy from any alternate energy production, small hydro or co-generation facility, with an electric generating capacity of up to eighty megawatts, under such rates, terms and conditions as the commission shall find just and economically reasonable to the corporation's ratepayers, non-discriminatory to co-generators, small hydro producers and alternate energy producers and further the public policy set forth herein; and (b) to provide supplemental or back-up power to any alternate energy production, small hydro or co-generation facility on a non-discriminatory basis and at just and reasonable rates; provided, however, that nothing contained in this section shall require any such electric or steam corporation to construct any additional facilities for such purposes unless such facilities are paid for in full by the owner or operator of the co-generation, small hydro or alternate energy production facility*." However, it is unclear how separable this passage is from the Federal PURPA statute that (at least the latter part of) the passage appears intended to implement.

While the passages above suggest that the PSC may have a basis for establishing an RPS applying to those electricity sellers within its jurisdiction, application to ESCOs would appear to require some form of "hook" or leverage. In many states, the utility commission's licensing authority over ESCOs provides a mechanism: compliance with an RPS can be established as a licensing condition. In New York, the PSC has not been granted direct legislative authority to license competitive ESCOs; rather the ESCOs have arisen out of regulatory settlements. As a result, the PSC has established guidelines for eligibility and an application for ESCOs to be deemed eligible. This registration step appears to fall short of asserting licensing authority (at least to date). Currently, an ESCO files and is declared eligible. Short of any change in information that would have caused the PSC to later deem the ESCO ineligible, there seems to be no opportunity to proactively revisit this granting of rights to sell at retail, under the existing procedures. Neither does there appear to be a clear path to impose or change conditions of eligibility, such as a licensing procedure that might require periodic filings or relicensing. One question that we do not have sufficient information to answer is: Is the PSC precluded by the restructuring settlements from altering the conditions under which ESCOs may operate in order to create a license that can be pulled for RPS non-compliance? Can the PSC retroactively apply RPS compliance as an eligibility requirement? Having not reserved such rights (at least based on our read of the PSC's web site), it would appear that a rulemaking might be required to exert such authority.

(Note: in some states, we might look to the authority to implement environmental disclosure. However, in New York this provides little precedent because the Environmental Disclosure rules, while requiring disclosure, place the burden for producing compliance labels on the disclosure administrator without specifying any enforcement or penalty mechanisms on ESCOs).

<u>Enforcement:</u> Finally, to implement an effective RPS the PSC would need some mechanism to ensure and enforce compliance. The PSC appears to derive sufficient authority to implement penalties under Public Service Law Article 1 § 25. Penalties:
"*1. Every public utility company, corporation or person and the officers, agents and employees thereof shall obey and comply with every provision of this chapter and every order or regulation adopted under authority of this chapter so long as the same shall be in force.*
2. Any public utility company, corporation or person and the officers, agents and employees thereof that knowingly fails or neglects to obey or comply with a provision of this chapter or an order adopted under authority of this chapter so long as the same shall be in force, shall forfeit to the people of the state of New York a sum not exceeding one hundred thousand dollars constituting a civil penalty for each and every offense and, in the case of a continuing violation, each day shall be deemed a separate and distinct offense."

Exercise of Authority to Implement an RPS
The final question is whether the PSC wants to exercise the authority it may have under New York law. This is an important consideration, because experience has shown that without specific legislation compelling and RPS, an RPS implemented by the PSC would most likely be challenged at the legislature and/or in court (we are not saying that such challenges would be successful, but we would anticipate that they would occur). It is our understanding that the legislature has not been receptive to such features of electricity restructuring, so this is an important consideration.

15. What are the dominant features of the retail choice environment in New York that will have the greatest influence of profitability of those selling green power?

Features of the retail choice environment in New York that have the greatest influence on the viability of an ESCO-based green power market and the profitability of those selling green power include:

- **Default service pricing –** e.g. is the “price to compare” from the provider of last resort set in a manner that prevents profitable entry into the retail market?
- **Uniformity of retail market rules** and (less importantly) default pricing across service territories.
- Broad, deep and effective publicly funded **consumer education** on issues relating to retail choice and the environmental impacts of electricity generation sources.
- Availability to ESCOs of wholesale suppliers of **all-requirements load-following service** willing to price their service at a reasonable level without too much risk premium.
- **Forward markets** that allow easy price (and quantity) hedging of the components of retail service.
- Availability of **merchant renewables.**
- Easy and low-cost, low-risk **mechanisms for acquiring renewable energy content** for green power offerings.
- Subsidies or **incentives for green power** sales (these have driven many of more successful green markets).
- **Inertia as an impediment** to switching retail electricity suppliers. One mechanism sometimes proposed to address this challenge is the allocation of customers that have not affirmatively switched to alternative competitive suppliers.
- **Free riding regarding public benefits.** The risk here is that purchasers (especially larger ones) do not capture exclusively for themselves very substantial long-term material value from purchasing a green product.
- The degree of **unbundling the retail bill** versus generation premium pricing will impact customer perceptions of price premiums. (e.g. a 1¢/kwh premium is a much larger percentage of the generation portion of the bill than of the entire bill).
- **Inclination of marketers to bundle a little new with much existing renewables.**
-

As we note below, even if these features were ideally aligned and impediments to green power marketing removed, the evidence still suggests that a well-designed RPS would have a greater impact measured in terms of increases in renewable energy than an exclusive reliance on market forces, absent full internalization of externalities into the price of competing forms of generation.

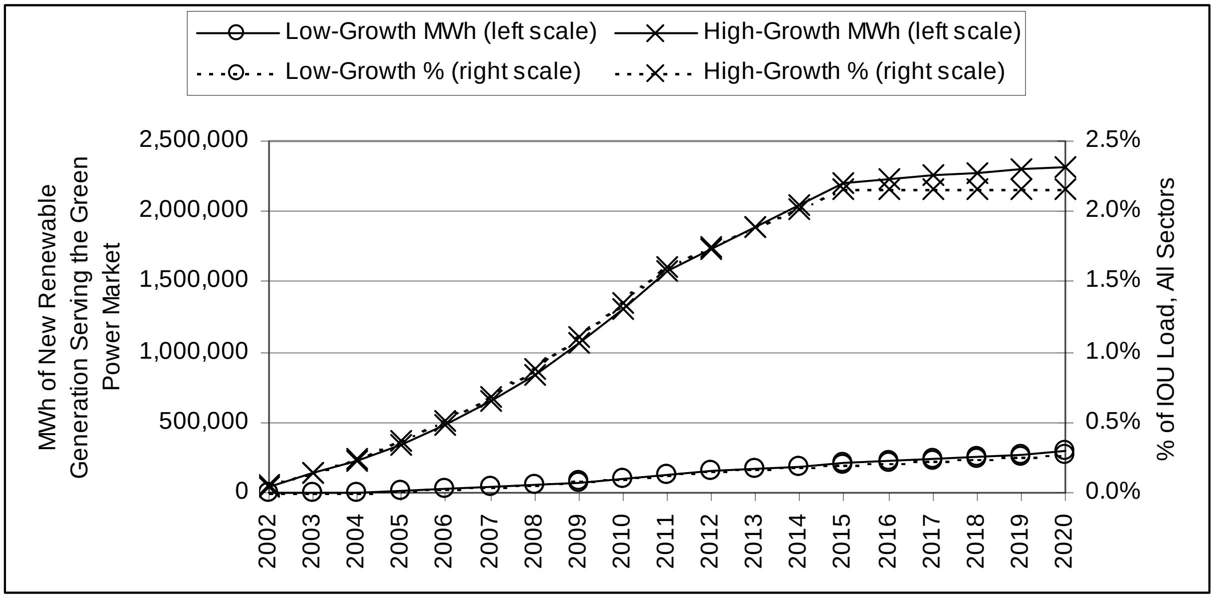
16. Environmental drivers appear to be the force behind the interest in renewables. Additional benefits of fuel diversity and economic development help justify public funds investment. While a RPS might be the easiest approach to deploying large amounts of renewables quickly, I still wonder if a competitive green power market, with many of the market impediments ironed out, will have a greater level of renewables deployment in the long run. Would it be more effective to address the existing market impediments or establish a RPS?

While ideally it may make sense to do *both* – address existing impediments to the growth of the green power market *and* establish an RPS (designed with the green power market in mind) – if the choice is one or the other, then the weight of the evidence suggests that a carefully designed and implemented RPS will be more effective than the green power market at deploying new renewables in a rapid and significant fashion.

Experience to date with green power markets in the U.S. and abroad has been modest. Even in states where impediments to growth appear to be low (e.g., Pennsylvania), green power markets – and customer switching in general – have been slow to develop. The most successful green power market in the world is in the Netherlands, where over 10% of residential customers have picked green power. This result has only been possible through heavy subsidization of green power products, however, as green power in the Netherlands can compete with conventional power only because of the available tax exemptions and other subsidies. In virtually every other green power market in the world, residential customer green power choice can been lower than 5%. We also note that green power products often contain only a fraction of new renewable resources. Thus, customer switching to green power will not necessarily lead to significant increases in new renewables supply. As these past experiences have been well documented (and at least implicitly acknowledged by NYSERDA in PON 599-01), we will not dwell on them here. Instead, we will look to the future.

To give NYSERDA a rough sense of the range of possible trajectories for New York's green power market, we turn to a model developed for the joint LBNL/NREL report, "Forecasting the Growth of Green Power Markets in the United States," published in October 2001 (authors Wiser, Bolinger, Holt, and Swezey). Although this report presents only national and regional forecasts, those broader forecasts were constructed from state-level data, so we do have the ability to look specifically at a forecast of New York's green power market through 2020. Keep in mind, however, that the assumptions behind the model (briefly described below) were in many cases generically derived, and therefore are not specific to New York or any other state. While this factor (along with many others, including the sheer duration of the forecast) potentially limits the accuracy of a state-level forecast, the outcome is nevertheless instructive in answering this question.

The following chart shows our model's low- and high-growth forecasts of new renewable generation brought on line through 2020 to serve the competitive green power market in New York, in both MWh and as a percentage of New York load (IOUs only, all sectors, 1% annual load growth rate assumed). While the gap between our low- and high-growth scenarios is large, even under aggressive high-growth conditions, our model forecasts that new renewables brought on line to serve the competitive green power market in New York will achieve less than 2.5% penetration of total IOU load by 2020. <u>Based on this analysis, one might conclude that a New York state RPS requiring new renewables deployment in excess of 2.5% of total IOU load by 2020 could achieve superior results (and perhaps with considerably less uncertainty) than could reasonably be expected to occur through the green power market.</u>



<u>Assumptions</u>

The high-growth scenario is intended to be aggressive, with sizable green power demand growth and steadily improving green power product content (e.g., the percentage of renewable energy contained in green power products increases). For such a growth pattern to develop, several general market characteristics might be required:

- market rules are conducive to competition and customer switching is high,
- consumer understanding and acceptance of green power shows significant growth, and
- the premium spread between the cost of renewable and competing generation technologies continues to narrow, because of ongoing reductions in the cost of renewable energy technologies, the continued or enhanced availability of renewable energy tax credits or financial incentives, or increases in fuel (i.e., natural gas) costs for conventional generators.

The low-growth scenario, on the other hand, is intended to represent a far less aggressive case, with more limited growth in customer switching and lower quality product content (e.g., green power products contain less renewable energy), and may be qualitatively characterized by a scenario in which:

- market rules are far less conducive to competitive suppliers and customer switching than under the high-growth scenario,
- consumer understanding and acceptance of green power grows only slowly, and
- the premium spread between the cost of renewable and competing generation technologies does not narrow appreciably.

To enable NYSERDA to judge the reasonableness of any of the specific assumptions that went into our model (and the graph above), here we provide specific details on our low- and high-growth assumptions.

- ***High-Growth Assumptions for New York:*** Residential green power penetration rates start at 1% in 2001 and increased by 1% each year until stabilizing at 15% in 2015. Non-residential green power purchases represent a constant 25% adder onto residential purchases (e.g., total green power penetration is 1.25% in 2001 and 18.75% in 2015 and thereafter). A constant 30% of the average green power product is assumed to come from existing renewables, while new renewables make up 2% of the average product in 2001, 5% in 2002, 10% in 2003, and will then increase by 2.5% every year thereafter until stabilizing at 30% in 2011.

- ***Low-Growth Assumptions for New York:*** Residential green power penetration rates start at 0.25% in 2003 and increased by 0.25% each year until reaching 4.5% in 2020. Non-residential green power purchases represent a constant 10% adder onto residential purchases (e.g., total green power penetration is 0.275% in 2001 and 4.95% in 2020). A constant 20% of the average green power product is assumed to come from existing renewables, while new renewables make up 1% of the average product in 2003, and escalate at roughly 1.5% each year until stabilizing at 15% in 2012.

Conclusion

While it is conceivable that actual experience in New York could deviate significantly from these assumptions (e.g., higher new renewables content in green power products), it is perhaps unlikely that even a wildly more optimistic high-growth scenario would change the ultimate answer to this question, which is that an effectively implemented RPS is likely to be more effective than the green power market in deploying new renewables in a sizable and immediate fashion. In other words, it is probable that any RPS established in New York would include standards that far exceed 2.5% new renewables by 2020 (e.g., Massachusetts' RPS requires 4% new renewables by 2009), rendering as moot any fine-tuning of our green power forecast.

While we make a strong case for the potential impacts of an RPS above, this is not to say that we would avoid the green power market altogether. To the contrary, we believe that removing impediments to the green power market should be given priority by NYSERDA and utility regulators. One of the principal advantages of the green power market, relative to an RPS, is that it may be able to generate a *sustainable* market for new renewable generation in New York that is not tied to ongoing publicly funded financial incentives. It may also help educate New Yorkers of the potential use and value of renewable energy in the state. Accordingly, while we believe that new renewable generation delivered from a carefully crafted RPS would easily outstrip that delivered by the green power market, we believe both strategies have merit and deserve close, ongoing attention.