



## **Power System Planning and Investment**

Draft Chapter for NEDRI Report  
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### **Summary:**

This Chapter focuses on the role that Demand Response resources can play in resolving reliability and congestion problems across the wires networks serving New England at both the regional and local levels. Restructuring, divestiture, and competition have changed the historic relationships between those who own and manage the regional power grid, those who manage local distribution networks, and those who supply electric power to customers. New system planning and investment strategies are needed in this new environment, and those strategies should be designed to incorporate demand response resources, which can offer low-cost, distributed solutions to reliability and congestion problems.

(A) NEDRI recommends a **regional planning and assessment** process that:

- Is regional in scope;
- Actively engages New England's state governments as well as the ISO;
- Is transparent and appropriately engages interested stakeholders and the broader public; and
- Comprehensively evaluates potential resource solutions.

(B) NEDRI also recommends a **regional power system investment policy** that builds on this planning process and that:

- Leaves investment and siting decisions in the hands of market participants and state regulators wherever possible;
- Permits broad-based cost recovery (regional socialization) where appropriate, but only where investments satisfy a least-cost standard of review; and
- Authorizes the same degree of assurance of cost recovery (i.e., "resource parity") for selected least-cost solutions to grid reliability and congestion problems, including transmission, distributed resources, and demand response investments

(C) Finally, we address the question of **distribution-level grid enhancement**. Wires companies in New England routinely invest more on *distribution* system expansion and upgrades than they do on expanding the *transmission* system. We conclude that the principles of least-cost reliability and resource parity are also well-suited to distribution system planning and recommend their adoption by wires companies and state regulatory authorities.

We conclude that these planning and investment policies would support both reliability and economic objectives for New England, and would allow demand-side solutions, including energy efficiency and price-responsive load, to deliver greater value to the region's power system.

NEDRI recognizes that regional planning and investment policies are complex, and raise many issues and choices for decision-makers. In the NEDRI process we have not attempted to address all of those issues, but have focused on those most directly connected to the potential role of demand-side resources. Those recommendations are set out below.

## **A. Introduction: The Role of Regional System Planning**

The New England electric system functions as a regional machine. The power sources and load centers, and the power lines that connect them, operate without regard for state boundaries. A fundamental question (and challenge) for the electric industry and its regulators is: How can we maintain a reliable electric system across this region at least cost over the long term? Demand-response resources are but one component of the answer to this question, but they have a potentially important role to play in maintaining a reliable grid at reasonable cost.

Electric transmission policies have traditionally been a low-profile topic even among electric utility executives and utility regulators; and environmental professionals rarely had cause to be concerned about them, except in the rare transmission siting case. That world has changed dramatically. Since the passage of the EPACT in 1992, the FERC has been engaged in a series of complex open-access and regional market initiatives that greatly change the role of transmission in the electric system. Transmission decisions are now critically related to the nature of regional electricity markets, the environmental footprint of the electric industry, and to the future of distributed resources, including demand-side resources. Transmission is no longer just an implementation tool for utilities to deliver power within integrated franchises, but is an avenue of commerce to connect multiple generators to multiple load centers, often at great geographic distance.

In its recently-released National Transmission Grid Study (NTGS), the DOE concludes that transmission constraints increase electricity costs and decrease electric system reliability to consumers in many regions of the country. The study identifies a number of policies that could promote investments in new transmission facilities, but also notes that demand-side options can play an equally important role in delaying or avoiding the need for those investments:

*Enabling customers to reduce load on the transmission system through voluntary load reduction or through targeted energy efficiency and reliance on distributed generation are important but currently underutilized approaches that could do*

*much to address transmission bottlenecks today and delay the need for new transmission facilities.*<sup>1</sup>

The NTGS includes several recommendations to support demand management, price-responsive load, and energy efficiency programs.<sup>2</sup> Since transmission operations and planning are done on a regional basis, the Study points out that “opportunities for customers to reduce their electrical demand voluntarily, and targeted energy-efficiency and distributed generation, should be coordinated within regional markets,” and concludes that regional planning processes “must consider ***transmission and non-transmission alternatives*** when trying to eliminate bottlenecks.”<sup>3</sup>

These aspects of the NTGS echo and expand upon the positions announced by FERC in recent RTO orders and reviews. FERC has made clear its view that transmission planning, transmission adequacy, and transmission pricing should be the responsibility of the nation’s newly-emerging Regional Transmission Organizations.<sup>4</sup> Thus, planning and expansion activities that historically have been conducted chiefly within state-regulated franchise utilities are now being taken up by regional transmission providers -- entities with virtually no experience with retail ratemaking, energy efficiency programs, distributed generation, or demand management.

Because most investments in transmission systems are recovered from ratepayers under regulated service rates, and because these investments often have broad societal impacts, a regional power system planning process is both necessary and desirable. A well-designed planning process can identify system needs, balance competing public interests (e.g., cost, reliability, environmental impact), and help to allocate scarce resources among potential investment choices.<sup>5</sup>

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<sup>1</sup>US Department of Energy, National Transmission Grid Study (May 2002) at p.41 (hereinafter NTGS).

<sup>2</sup>The DOE study includes many of the topics under discussion within NEDRI -- demand-side bidding, price-responsive load, advanced metering, demand-side participation in ancillary service markets, increased support for energy efficiency programs, and regulatory policies to eliminate utility disincentives to efficiency and distributed generation. See NTGS pp. 41-45.

<sup>3</sup>NTGS p. xiii (emphasis added).

<sup>4</sup> Recent FERC orders refer to these regional organizations as Independent Transmission Providers (ITPs). The change in nomenclature does not affect the FERC’s expectation that regional transmission entities will be responsible for transmission adequacy and expansion planning.

<sup>5</sup> The sums involved can be quite substantial, and unlike the costs of competitive generation, are proposed for collection in non-bypassable tariffs. NEDRI participants are aware of the significant transmission investment proposals now pending in the region, totaling well over one billion dollars. If these transmission investments are made, the costs will ultimately be borne by electric ratepayers, however they are assigned throughout the region.

The case for improved transmission system planning and investment policies in New England is not merely theoretical. The absence of an adequate system planning process has led to several serious problems, including:

- Transmission siting proposals are not timely compared with the needs they are intended to address, nor are they generally prepared with due consideration for alternatives;
- Generation is built that causes transmission congestion;<sup>6</sup>
- Regional environmental concerns are not considered in a structured way;
- Customer resources are not considered a significant strategy to mitigate forecasted system needs, nor are circumstances in place to enable this consideration, except as an after-thought.<sup>7</sup>
- Some resources are called forth by market forces, others by monopoly processes – these collectively address the same needs and are not coordinated.

ISO-New England currently administers a process called Regional Transmission Expansion Planning.<sup>8</sup> The ISO has taken significant steps to make this process accessible and has opened the door, at least in theory, to customer-based resources. While meaningful progress has been made through RTEP, we conclude that a significant change in the process is required to achieve New England’s target levels of reliability in a least cost manner.

A process that is widely understood to meet the standards set out in this Chapter would also improve the confidence of the public that the economic and environmental implications of grid investment decisions were being addressed thoughtfully. An indicator of success would be a diminishing of the frequency of “reliability crises” where time is “running out” and only the most direct and often most intrusive solution seems to be available to mitigate the crisis.

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<sup>6</sup> Over the past few years, new generation was sited in Maine to take advantage of siting opportunities and new natural gas supplies, even though it was foreseeable that more generation was proposed there than could be used for Maine’s needs, or moved out of the state via the existing transmission system. This has not caused a reliability problem in Maine, but has created an economic congestion problem. Units with low running costs are sometimes idled in Maine, while units with higher costs are running elsewhere in New England. Generation in Maine is said to be “locked in” and cannot be fully used to address reliability needs elsewhere in the region.

<sup>7</sup> Customer resources include consumer-funded energy efficiency, customer-sited generation, and demand response programs. They may also include regulatory pricing strategies or rate designs designed to induce customers to avoid energy use or shift the time of its use. Building codes and appliance and equipment standards can also be viewed as resources that can help to resolve reliability and congestion problems.

<sup>8</sup> As with many similar efforts, the name itself (Regional *Transmission Expansion* Planning) underscores a limitation in the way the task is defined, and the need to launch a planning effort that is open to both transmission and non-transmission solutions to power system challenges.

## **B. Recommendations for Regional System Planning**

**Overview:** NEDRI recommends that the ISO,<sup>9</sup> regional market participants and states create a new regional planning entity and a planning process that would seek out low cost grid management solutions from all types of resources – traditional grid upgrades, operational improvements, strategically-located generation, and targeted investments in demand response resources. We recognize that the structure, authority, and governing rules for a regional planning entity will be critical to its success, but decisions on those topics will be taken in other forums, and we do not focus on them here. However, whatever structure is adopted for regional system planning, it must be one that accommodates a long-term view of the system, and can openly evaluate the potential for demand response resources to resolve grid problems. Thus, the recommendations below focus not on the structure or governance details of a regional planning entity, but on the basic principles to support an appropriate balancing of resources, including demand response resources, in resolving power system challenges.

Key elements of the planning process include:

- Government, working regionally, would have a significant role;
- The process would be built around identifying deficiencies in the electric grid;
- These deficiencies would be screened for reliability or severe congestion implications;
- For these situations, the planning process would assess all the solutions, alone and in combination, that could reasonably and sufficiently address the deficiency;
- The method of paying for all the solutions would be the same;
- The system operator would be relieved of the burden of balancing public policy (which it has no reliable way or standing to judge) and its technical tasks, and could concentrate on operating the system.

### **Recommendation 1: Increase coordination among the states and between the states and the ISO.**

As a starting point, NEDRI recommends increased cooperation on regional power system issues among the six states and the ISO. At present, neither the ISO nor any other entity is structured and empowered to adequately reflect public policy in resource deployment on a regional scale. A robust planning capacity, reflecting the interests of all of the states and the region as a whole, is needed to address regional needs for transmission, for congestion relief, and for long-term resource adequacy.<sup>10</sup>

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<sup>9</sup> ISO-New England has announced that it will take steps to transform itself into an RTO. The recommendations in this paper apply to whatever organization becomes the duly constituted system operator for the New England region. For purposes of consistency, we will refer to that organization as “the ISO.”

<sup>10</sup> NEDRI is not alone in raising the need for greater coordination among states in regional power system planning. FERC has focused on the need for regional coordination in planning, specifically noting that regional entities could establish resource adequacy standards. The National Governors’ Association has also launched a review of potential roles for such Multi-State Entities. See, e.g., Brown, Ethan W.,

The relationship between the ISO and the states is important. Increased participation by the region's state governments should be organized so as to accomplish the following:

- Add efficiency to regulatory decision-making;
- Add certainty to the marketplace;
- Guide the ISO toward the most efficient planning process;
- Avoid duplication of effort; and
- Protect the ability of state PUCs and siting authorities to conduct independent reviews of proposals subject to their jurisdiction.

These objectives are discussed briefly below.

**Add efficiency to regulatory decision-making.** Regulatory matters with regional implications are challenging for individual states. The most obvious of these is siting transmission facilities that physically cross state lines, or which have significant effects in multiple states, even if the assets are concentrated in one state only. The easiest but not necessarily best path for a state considering a regional project is to consider only the effects on the state, ignoring other effects.<sup>11</sup> A regional body that can sort through the societal effects, both environmental and financial, may make the deliberations of the responsible states more effective. This is especially appropriate when the practice known as regional uplift applies, in which the whole region pays for the cost of the improvement if it meets criteria of regional significance.

Simply adding a second full-scale regulatory process on a regional scale, especially if states will not apply great weight to regional findings, would not be an improvement.

**Add certainty to the marketplace.** In cases where siting or regulatory actions in multiple states are necessary, the findings from a regional examination of the issue can be useful to guide each of the states, providing them with a common and public interest-driven set of findings from the perspective of the region as a whole.

**Guide the ISO toward a more efficient planning process.** Without fuller knowledge of the intensity of the regional effort, it is hard to be specific about the nature of its relationship with the ISO. It would be important for the quality engineering work of the ISO to be recognized and not duplicated. The concern here is that the current RTEP process comes up short in reflecting public policy concerns in the ISO process. Alternatives are not fully considered. A sustained effort to engage states, their utilities and their customers in addressing emerging and full-blown reliability and congestion

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*Interstate Strategies for Transmission Planning and Expansion*, National Governors' Association Task Force on Electricity Infrastructure, 2002. The New England states are also engaged in a parallel process, coordinated by the New England Governors' Power Planning and Environment Committees, discussing what, if any, regional structure or cooperation is appropriate.

<sup>11</sup> Ohio is the only state we are aware of in which the statute gives the Public Utility Commission explicit authority to cooperate with other state commissions in reviewing the siting of an inter-state transmission line.

problems does not happen. A new relationship would focus on improving these elements.

**Avoid duplication of effort.** As noted above, reliance on ISO engineering is sensible – technical analysis and engineering is what the ISO does well. States, of course, always reserve the right to conduct due diligence reviews of the work of the ISO, or others, as part of state siting and (where relevant) rate approval processes. Because the ISO and the states bring different skills and perspectives to the process of system review, a combination of their efforts may be quite useful to the region.<sup>12</sup>

**Protect independent state reviews.** States must retain their ability to rule on issues subject to their jurisdiction and responsibility. Thus, any regional effort must be designed so that state decision-makers can retain their quasi-judicial independence. For a regional effort to be valuable, however, it is important that states apply significant weight to its findings. This is among the reasons that the NGA task force and others suggests a separate organization related to the states, but also distinct from them.

**Recommendation 2: Conduct a continuing regional power system planning process to identify system needs and alternative strategies to meet them.**

Regardless of the structure that New England chooses to employ for regional system planning, the states and the ISO should participate in a continuing power system planning process that takes a long-term view of system needs, and identifies both traditional and non-transmission alternatives to resolve them.

NEDRI recognizes that the existing Regional Transmission Expansion Planning process addresses most of the issues noted above. However, we conclude that the RTEP process needs improvement in some critical respects:

- It should provide a more formal role for state governments, and thus ensure more active participation by state officials: utility regulators, energy offices, consumer advocates, and environmental regulators, as appropriate to each state;
- It should increase its focus on geographic target areas, and actively involve consumer and citizen interests in the planning process, relying less exclusively on traditional market players to guide the planning process;

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<sup>12</sup> A model for organizing the staff for regional planning is the Northwest Power Planning Council, which includes a small permanent staff (providing continuity and technical expertise) and state staff members on detail from state regulatory bodies (providing close contact with state-level issues, and an understanding of the policy setting for regional decisions.) As for funding, a combination of state and regional sources could be considered. State staff and coordination efforts could be from the states themselves, while regional technical planning and analysis could be supported by the ISO. Or, if a more formal entity were created, and the entity became viewed as an essential element of a regional electricity market, it could be supported wholly on a regional basis, recovered through the wholesale tariff of the ISO.

- It should provide a structured role for, and make increased efforts to call forth, non-transmission alternatives to grid reliability and congestion problems.

Because of the inherently “outsider” status of the ISO in the states, state governments are important in fostering this more comprehensive effort to address system needs. Because the more significant system needs cross the boundaries of distribution companies and states, a regional approach is the only reliable way to address system needs so that all solutions are considered.

The focus of the regional power system planning process<sup>13</sup> should be to identify emerging system deficiencies, and attract resources to address them. This is distinct from a “proposal review” process, which would simply evaluate and react to individual proposals by project developers.<sup>14</sup> Instead of winding up with the accumulation of individual and largely unrelated decisions, the process would have an overall objective, and proposals meeting that objective would be clearly identified. Going further, the process would solicit and select system enhancements that would be advanced by market participants or supported through the ISO wholesale tariff.<sup>15</sup>

Transparency would be a fundamental characteristic of the planning process. The reasons for priorities and decisions should be publicly stated, and clear to observers. Information for the planning process will come from market participants and individual states. The planning process would integrate, not just sum, this information.

The planning process would be cyclical. A periodic assessment of the electric system would be produced, identifying deficiencies of varying types and urgencies.<sup>16</sup> The process would focus on mitigating system deficiencies. All opportunities to mitigate a deficiency or slow its development would be solicited and evaluated for their costs and benefits.<sup>17</sup> A sufficient planning horizon (7-10 years) would be necessary to enable the

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<sup>13</sup> While the precise name is not critical, the concept is. Most discussion of this sort come under the heading of “transmission planning,” “transmission expansion,” or “grid enhancement.” Such terminology excludes, or at best minimizes, the role that non-transmission alternatives may play in resolving reliability and congestion challenges. A critical feature of the planning process recommended here is that it will openly consider non-traditional transmission actions, and supply-side and customer-located resources as potential lower-cost solutions to power system problems.

<sup>14</sup> A symptom of this condition is queuing – the current ISO practice of treating all projects fairly by reviewing them in the general order their qualified application is complete. Relationships among projects to address common needs can be overlooked.

<sup>15</sup> Other transmission, generation, or demand side investments in the system may be desirable from a purely economic (non-reliability) perspective. These can be developed on a merchant basis.

<sup>16</sup> NEDRI participants conclude that an annual cycle is unlikely to provide sufficient time for all the necessary analysis. An appropriate period between system assessments, perhaps two years, would be used based on realistic assessments of the tasks.

<sup>17</sup> Comparing different resource mixes to resolve grid problems is an emerging art. This paper is based on the idea that the solution menu would be complete, and that the relevant aspects of each potential solution to solve reliability and system problems would also be considered. For example, an assessment of the persistence of the solution (i.e., will it be there?), the variability (--will it change?) and reliability (--will it be what the system operator expects when it is called?) is appropriate. Probabilistic approaches will enhance the results, but in any case, the method for evaluation should be sufficiently supported.

aggregation of small scale resources to have a meaningful effect on a significant system need.

A planning horizon of this length also allows the industry (ISO, LSE, distribution companies, regulators) to prepare consumers in sensitive areas for the choices they are likely to face. Experience teaches that significant opposition to projects – even those that are truly needed to address pressing system deficits -- arises from the mistrust, surprise and fear of affected people. A process that provides objective and trusted information to the people and communities who are asked to absorb the costs and impacts of system investments will tend to inspire confidence in the needs assessment, and is less likely to produce intense project opposition.

Routinely, one round of proposals to mitigate any deficiency would occur in each planning cycle. The same deficiency may emerge in successive analyses, its condition worsening or improving depending on the combination of demand and system changes that occur in the interim. The effect of this approach is that low-cost mitigating actions may be applied first, and higher cost actions can be delayed until they are truly needed and valuable.<sup>18</sup>

**Recommendation 3: The outcome of a regional power system planning process should be an evaluation on an even-handed basis of a wide range of feasible solutions to emerging problems, including investments in generation, transmission, and demand-side options.**

To anticipate and resolve transmission challenges and bottlenecks requires analysis of a range of potential solutions including transmission investments, transmission operations, strategic generation, and demand-side programs and investments. As the National Transmission Grid Study concluded,

“Expansion of the transmission system must be viewed as one strategy in a portfolio to address transmission bottlenecks; this portfolio also includes locating generation closer to loads, relying on voluntary customer load reductions, and targeting energy efficiency and distributed generation.”<sup>19</sup>

NEDRI recommends that the regional planning process employed in New England be organized and conducted with a clear capability to assess all technically feasible, reasonably-priced solutions that could meet reliability objectives. This recommendation applies to whichever planning process is employed -- the existing process, or one with significantly increased state government participation recommended here, or a different

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<sup>18</sup> One concern is what happens if a system deficiency flares up in mid-cycle. With a sufficiently long time horizon, the chance of a surprise is minimized. A sudden change in the system (loss of a large amount of generation due to random, regulatory or other causes) can, however, create a difficult and immediate problem to solve. As the ISO has done in Southwest Connecticut in recent years, this sort of emergency program of acquiring resources quickly must remain a part of the toolbox.

<sup>19</sup> NTGS at p.51. For the range of options considered, see NTGS at pp33-38 (operations), pp41-45 (demand-side and distributed generation), pp61-67 (advanced technologies), pp50-60 (transmission investment and siting).

new process altogether. The region’s planning process should develop a complete array of potential solutions to system deficiencies, and evaluate them for their contribution to reliability and least cost objectives. This approach is consistent with the view recently expressed by NECPUC, which urges the ISO to “develop a resource planning protocol that is based on resource parity and involves a full and complete analysis that will identify the project which will be the least cost solution to the problem.”<sup>20</sup>

Prospective solutions may be offered by private sector competitors (merchant generation, merchant transmission, curtailment service providers), or from monopoly providers (e.g., transmission utilities, or state-organized, intensive, targeted energy efficiency programs.<sup>21</sup>) The planning process should evaluate them on an equivalent basis based on how well each solution would address the deficiency. It would be at this point that the efficient reliability standard (described in Recommendation 5, below) would operate.<sup>22</sup>

### **C. Recommendations -- Regional Power System Investment Policy**

The regional system planning process outlined above provides the critical foundation for major power system enhancements. Most significantly, it will identify emerging reliability and persistent congestion problems, and evaluate potential solutions that could mitigate or resolve them. System operators have traditionally focused on supply-side resources in meeting reliability requirements for electric networks, especially in periods of stress. However, for many system needs, there is a demand-side corollary that could perform that same service at lower cost, provided that market rules were defined to include such resources, and broad-based funding were made available to support them on the same basis as the more traditional solutions. The recommendations in this section are intended to ensure that competing grid solutions – supply, wires, and demand-side – will be treated comparably in public decision-making, and will have equal access to tariff-based funding.

**Recommendation 4: Leave investment and siting decisions in the hands of market participants and state regulators wherever possible, assigning cost responsibility to those who create the need for system upgrades, and those who benefit from them.**

After grid problems and potential solutions are identified in the system planning process, these results should be posted publicly so that market participants can consider what actions they might take within the existing market structure to meet emerging needs.

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<sup>20</sup> Letter from NECPUC to ISO-NE (“Re: Regional System Planning”) dated February 4, 2003. In this letter NECPUC explicitly endorses the principles of system resource (not just transmission) planning; resource parity among wires, supply-side and demand-side solutions; and a least-cost decision rule for preferred solutions. These recommendations parallel NEDRI’s recommendations here.

<sup>21</sup> Intensive energy efficiency means that programs with higher screening costs are deployed, justified by higher long run avoided costs driven by growth and reliability needs. It could also mean expanding the eligible services or population from what is otherwise generally available.

<sup>22</sup> See Recommendation 5 below.

Wherever possible, market-based and state-based responses to system needs should be permitted to emerge.<sup>23</sup>

NEDRI participants recognize that assigning causes and costs to these categories is a matter of judgment as much as engineering science, but we conclude that reasonable judgments about cost-sharing can and must be made.

Public, regional intervention to promote or pay for grid solutions should be taken only where it is evident that adequate resolution is not forthcoming in the market, or that the investment in question is one that, as a matter of equity, ought to be undertaken by grid managers with cost recovery imposed through tariffs.

**Recommendation 5: The ISO, NEPOOL, and FERC should apply an “efficient reliability” test, based on principles of least-cost analysis and resource parity, when considering proposals to socialize the costs of system improvements through wholesale rules and transmission tariffs.**

Resource adequacy and system reliability across electric networks are classic public goods, provided to all interconnected users on essentially the same basis, and not easily withheld from any interconnected user. NEDRI participants believe that efficiently constructed wholesale electricity markets, including adequate demand-side bidding systems, will moderate both the volatility of markets and the degree to which reliability managers must intervene in the market to ensure reliable service. Nevertheless, reliability and power market managers will still find it necessary to take administrative actions to promote reliability. And typically, they seek to recover the costs of these administrative actions in broad-based rates charged to all users of the grid. In such cases, decisions should be governed by two important principles<sup>24</sup>:

- *Resource parity*: Energy efficiency, load management, demand-side bidding, and distributed resources – in addition to traditional generation and transmission resources -- are all potentially cost-effective means of meeting reliability needs identified by system operators and power pool managers. NEDRI recommends that when socialized cost recovery is sought, that demand-side resources be treated comparably to supply-side and wires options both in analysis and in access to funding.

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<sup>23</sup> Note, however, that the conditions for efficient markets in electric services must be carefully considered. There are a number of key market and policy conditions that would provide a foundation for solutions to emerge without regional intervention. Some, like region-wide locational marginal pricing, are outside the scope of NEDRI’s work. Others, such as creating markets for price-responsive load, and ensuring resource adequacy eligibility for demand-side resources, are taken up in other sections of the NEDRI report. Where market structures and market barriers would impair the contribution of demand response resources, investment policies can not rely on markets alone.

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- *Least-cost standard:* A principal criterion for selecting a solution that is qualified to receive socialized support should be whether it is the lowest-cost, reasonably available solution to an unmet system need, considered on a total cost basis.<sup>25</sup>

**NEDRI recommends that NEPOOL, the ISO, and FERC adopt the following standard as a means of screening proposals to socialize grid enhancements:**

Before “socializing” the costs of a proposed reliability-enhancing investment through tariff, uplift, or other cost-sharing requirement, the ISO (and FERC) should require the applicant to demonstrate:

- (1) That the relevant market is fully open to demand-side as well as supply-side resources;
- (2) That the proposed investment is the lowest cost, reasonably-available means to correct a remaining market failure; and
- (3) That benefits from the investment will be widespread, and thus appropriate for support through broad-based funding.

If this standard were adopted as a screening tool when considering proposed reliability-enhancing rules and investments, it would provide a much-needed discipline in situations where expensive wires and turbines solutions are proposed to address reliability problems, particularly where more robust, less expensive, distributed solutions may be overlooked.

In making this recommendation, it should be noted that NEDRI is not recommending a comprehensive least-cost planning procedure for the New England Power Pool or the region.<sup>26</sup> Comprehensive utility planning has been put aside in most New England states in favor of increased market competition, or (in Vermont) is still practiced by local utilities under state authority. The efficient reliability test is triggered only in those instances where governmental decision-makers are intervening in the market to acquire

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<sup>25</sup> It is important to recognize that different solutions will bring different values to this analysis. Demand-side solutions will often lower line losses and distribution costs, and will likely deliver power cost and environmental savings, as well as the grid enhancements being sought. Grid planners should consider all of these costs and savings when considering the net project costs of demand-side option. A further question is whether non-electric societal values (air quality, water quality and supply, for example) would factor in. NEDRI supports some inclusion of societal values and would rely on the participation of states in the planning process to articulate how to do that.

<sup>26</sup> There are likely to be desirable features to a form of indicative planning or “guidance planning” by the states acting together on topics such as resource diversity, resource adequacy, and congestion avoidance, but this is not the topic here. As noted in the text, the efficient reliability test focuses on securing the least-cost, reasonably available investment to solve a public problem that is going to be paid for by the public.

resources, such as transmission upgrades, that will be paid for through utility tariffs, and not through voluntary market prices.

### **Recommendation 6: Ensure comparable cost recovery opportunities for transmission and non-transmission resource solutions**

In its recent policy proposal on transmission investments, FERC states:

“We realize that the most timely and cost-effective ways to meet demand for additional grid capacity will not always be additional transmission facilities; rather, they may be innovative operating practices, ...distributed generation, demand response or demand-side management. We invite comments on what actions other than investments in new facilities should receive incentives, what form those incentives should take, and how we can encourage them.”<sup>27</sup>

This statement by FERC is consistent with the National Transmission Grid Study, which recommends that “(w)here possible, solutions to bottlenecks should be solicited through open, competitive processes that allow private developers to offer proposals that might encompass new transmission facilities, non-transmission alternatives, or both.”<sup>28</sup> NEDRI supports both the FERC observation and the Grid Study recommendation.

However, we note that a major challenge in attempts to expose transmission proposals to “all-source” bids is the asymmetry in risks to investors. Transmission investors know that where the costs of transmission are included in a utility’s rate base or under an ISO tariff, their costs can be recovered in non-bypassable, tariffed rates. Absent an “equal access” rule, providers of non-transmission alternatives have no such option, and thus must assume a much higher set of market and investment risks.

NEDRI recommends that NEPOOL, ISO-NE and FERC remove this asymmetry through adoption of a “**resource parity**” principle, which would provide equivalent cost-recovery opportunities for all investments that are selected through the regional planning process, and which satisfy the efficient reliability test set out above. Whether a grid problem is resolved through a transmission or non-transmission solution, or a combination of them, the solution should qualify for cost recovery through transmission tariffs or wholesale uplift charges on the same basis.<sup>29</sup> (For a brief explanation of the steps in this process, see Appendix B, below.)

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<sup>27</sup> FERC, “Proposed Pricing Policy for Efficient Operation and Expansion of Transmission Grid,” Docket No. PL03-1-000 (January 15, 2003) at para. 32.

<sup>28</sup> NTGS at p.52.

<sup>29</sup> An important option to consider is an “open season” bidding process to meet system needs, in which all winning bidders are given the same access to the tariff to return their costs. However, even in the absence of an open season, a proposed planned solution (such as a planned transmission upgrade) can provide a “price to beat” for non-transmission alternatives. Those who commit to provide a grid solution through

In addition, it will be important that reliability and transmission planning processes be fluid enough so that ISO analyses under the least cost and resource parity principles are updated and revised over time. Transmission planning often takes a long time, while market-driven, economically attractive alternatives may have shorter lead times, and may appear after a “build” decision is reached on the transmission alternative. To support both competitive markets and reliability objectives, the ISO transmission planning process should allow for changes in conditions that may reveal different reliability solutions (whether demand-side resources, distributed generation, or something else). In such cases, FERC’s standards for cost recovery should encourage the “later look” and allow for cost recovery of planning and development costs when an approved transmission project is prudently curtailed in favor of a less costly alternative.

## **D. Recommendations -- Distribution Power System Planning**

**Overview:** Throughout New England, electric distribution is a fully-regulated monopoly function, and the total costs of distribution comprise a substantial portion of the overall cost of electric service, significantly exceeding the cost of transmission. Rapid and/or concentrated load growth on portions of the distribution system can impose reliability problems and expensive upgrades on local networks. Demand response resources that are targeted to those hot spots can quickly moderate local reliability problems, and can defer costly upgrades, lowering the cost of distribution services.

Distribution utility companies should organize a planning process for the distribution system that identifies the locations on the local grid that could benefit most from targeted addition of demand resources. They should seek to deploy those resources through their own actions, by targeting state and regional DR efforts, and by offering distribution credits to those deploying especially valuable demand resources on the local grid.

**Recommendation 7: New England’s electric distribution companies should seek out and acquire cost-effective demand side resources that would improve the reliability, operation and economics of the local distribution system. They should do this in the context of an ongoing planning process focused on the distribution system that considers all available resources to meet distribution needs. Investments at the distribution level should be guided by the principles of efficient reliability, least cost, and resource parity, just as they are at the transmission level.**

### **Discussion**

**Regional and distribution needs differ.** Discussions of demand response deal with system load conditions on a large-scale, aggregated basis – for example, regional or subregional daily peaks, or persistent congestion over large area for a long period of time. Distribution-level problems, though, are much more localized, both in space and time.

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other means should be given the same access to socialized funding as those who propose to use that funding for transmission upgrades.

Instead of worrying about overall system peaks, distribution managers must be concerned with peak loads on individual transformers, feeders, and lines. These peaks may, and often do, occur at different times of the day or year than do system peaks and may grow even when the total system peak declines.

The planning horizon for the distribution system also differs from that of the transmission and generation sectors. Commonly the approach to meet peak demand has centered on generation and transmission resources that have a planning horizon of five, ten, or even thirty years. Distribution planning, however, offers a different process, one where planning can take place on a shorter time scale, sometimes as little as weeks or months out to three to five years.

For both of these reasons DR policies and programs that address regional peak load challenges and large-scale transmission needs (while valuable in their own right), will not necessarily provide the most economic or reliable solutions to local distribution challenges and cost drivers. Those challenges should be addressed through a distribution planning and investment process that identifies reliability needs on a localized basis, and is open to the most cost-effective solutions, including DR resources, to address them.

**Distribution planning traditions.** Distribution engineers have, for decades, largely employed the same methods to plan and expand the system and to solve specific problems. Because of safety and reliability concerns and because of the industry's culture of monopolistic control, distribution utilities have not typically embraced new or innovative ways to solve problems, especially where solutions may lie on the customer's side of the meter. Fairly rigid and traditional engineering criteria have driven the decision-making process. Engineering solutions usually result in larger wires and transformers or other system add-ons, such as capacitors.<sup>30</sup> The overriding need for adequate and reliable delivery, while important, tends to inhibit the adoption of innovative and less costly means of serving customers.

Traditionally, the distribution company has seen its customers as a service requirement -- the customer presents the need and the company must serve it. The customer has rarely been seen as a source of system resources. Distribution engineers justify improvements to the distribution system as line loadings rise to levels where the cost of line losses exceeds the cost to increase conductor size or voltage, or when voltage sags are too great. They are generally not asked to think about how to reduce risk to customers from volatile energy prices and generator market power, and local distribution plans may not address the aggregated implications of load growth among several circuits in a load center on the transmission system.

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<sup>30</sup> Distribution system costs can generally be divided into two groups: transformers and substations, and lines and feeders. Transformers and substations are both the first and intermediate interfaces between transmission and customer-level service. Feeders generally connect the highest voltage transformers to intermediate level transformers. Lines carry the lowest distribution voltage power to individual customer transformers and drop lines.

Demand resources have rarely been identified or pursued based upon their particular value to the distribution system, as opposed to their more general value in deferring overall load growth or overall system peaks.<sup>31</sup> While energy efficiency has been a priority in some states during some of the past fifteen years, in many of these cases, it is seen as a social program, or an “add on,” and not as an integral element of electric service, and especially not as an element of the distribution service.

Interruptible contracts have been struck between utilities and customers for many years. In these deals, the customer receives a discount in consideration for accepting the chance of some interruptions, a degraded level of service. In most cases, however, there has been an expectation that the utility would not use these interruption options; moreover, since customers could opt out of the relationship on relatively short notice, distribution planners have not wanted to rely on them to protect distribution-level reliability.

**Demand response opportunities.** The local distribution network occupies a pivotal place with respect to the delivery of demand response resources. It has a mandate to operate its system in a least cost manner to achieve reliability objectives. It has a deep connection to customers, and it has the opportunity to deploy cost-effective resources and to include DR costs in rates when they will lower the cost of distribution service.

Our growing experience with distributed resources reveals that distribution expansion and reliability needs can be met not only with equipment similar to what is currently in use but also with new grid technologies and investments on the customer side of the meter. Distributed Resources, including dispatchable demand response, distributed generation, and long-term energy efficiency, can provide low-cost reliability benefits and can defer expensive distribution investments. The distribution company may enjoy avoided or delayed investment costs<sup>32</sup>, reduced energy cost volatility, more economical provision of ancillary services and other benefits by deploying these resources.

**All-resources distribution planning process.** What would an enhanced distribution planning enterprise look like? First, the planning horizon would be as long as demand forecasts allow. Distribution companies would enhance their effort to project increased electricity use of their customers by getting a discrete understanding of each circuit. In the hub and spoke design of most distribution systems, the company would approach each circuit as a system.

With each circuit characterized by expected customer needs, the distribution planner determines if there is a potential need for investment within the planning horizon. If so,

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<sup>31</sup> A particularly instructive exception is Green Mountain Power’s Mad River Valley project, in which an expensive feeder and substation upgrade was consciously deferred through targeted energy efficiency and load management in the service area surrounding a substation in one of Vermont’s rapidly-growing ski area communities. See Cowart, et al., “Distributed Resources and Electric System Reliability,” (RAP 2001) at pp16-18. (posted at [www.raonline.org](http://www.raonline.org))

<sup>32</sup> Even where demand-side alternatives, such as energy efficiency, load management, and distributed generation may not permanently avoid distribution investments, they can still provide meaningful value by delaying more expensive investments – the longer the delay, the greater the value. The challenge is to incorporate these assessments into utilities’ routine planning procedures.

there is now an avoidable cost specific to the circuit. Alternatives on both sides of the meter can be considered to address the need.<sup>33</sup>

The cost of customer-based alternatives would include the cost of any incentives needed to entice the customer to participate. These costs could include more intensive efforts or higher cost-shares for energy efficiency than are typical elsewhere in the service territory, incentives to customers to install distributed generation, and payments under demand response tariffs.<sup>34</sup>

As part of the analysis of trade-offs, each utility or regulatory body would have to choose a cost-benefit test. We recommend a broad societal test that reflects all values, including risk and environmental factors.<sup>35</sup> In this enhanced form distribution planning, there is an increased likelihood that the alternatives of highest value are deployed by the many actors working in the distribution and retail market venues.

**Implementing distributed utility planning.** Modifying the distribution system planning process to seek out and acquire customer resources will require careful attention, both by utilities and by regulatory agencies.

To begin with, state regulatory commissions should consider policies changes that would support cost-effective distribution investment practices. Three types of policies should be examined. First, as noted above, distribution company regulators should consider adopting rules that would require the distribution planning process to consider DR resources when resolving growth and reliability problems. Second, they should examine tariffs and policies for special contracts that would accommodate the incentives or credits necessary to enroll customer resources in distribution support programs. States may wish to adopt new tariffs to reflect these new financial relationships, which differ from the averaged distribution rates and bases for interruptible contracts now in effect.<sup>36</sup>

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<sup>33</sup> If not, utility-wide or region-wide needs may still call forth customer resources from the circuit.

<sup>34</sup> For distributed generation, there are three important points to keep in mind. First, it is important that there be an interconnection standard available to accommodate those combined energy and power installations where economic are served by a grid connection. Second, there should be a cost-based tariff for back-up power. Third, distributed generation should not create or exacerbate air quality problems. *See, e.g., "Model Regulations for the Output of Specified Air Emissions from Smaller-Scale Electric Generation Resources,"* Regulatory Assistance Project, October 31, 2002.

<sup>35</sup> Some jurisdictions prefer to focus only on market-oriented values. If so, the "ratepayer-impact test," which seeks to assure that no customer's rates are raised due to the investment in question, would be particularly inappropriate. It would make no sense to apply the test to DR investments that defer distribution upgrades if it were not also applied to the upgrade itself. We are unaware of a utility or commission that has ever applied the RIM test to proposed distribution upgrades needed for local reliability.

<sup>36</sup> One potentially important tariff option applies the concept of localized distribution credits to customers that provide valuable deferral or reliability services to the local grid. The use of special distributed resource credits can encourage customers to install needed resources in the high-cost parts of the system or as part of a customer-specific development, thereby avoiding more costly investments in distribution. This helps overcome customer barriers to investment in distributed resources and secures the investment value for the utility and its customers. *See* Moskovitz, et al, "Distributed Resource Distribution Credit Pilot Programs: Revealing the Value to Consumers and Vendors" (RAP 2001) posted at [www.raponline.org](http://www.raponline.org).

States should also examine whether current ratemaking policies linking the distribution company's corporate net income to energy sales create a barrier to its pursuit of low-cost efficiency resources on the local grid. Even where distribution upgrades are more expensive than their demand-response alternatives, some distribution utilities may be reluctant to invest in the lower-cost resource. Because distribution tariffs are heavily weighted to volumetric sales, customer energy efficiency tends to reduce net margins, at least in the periods between rate cases.<sup>37</sup> Performance-based ratemaking plans for distribution utilities, and policies that provide stable revenues regardless of sales volume are options that regulators could examine to remove this barrier and reward utilities for lowering overall distribution costs.<sup>38</sup>

At the utility level there remains a technical and cultural challenge to redirect distribution planners to think about their role in the company in a new way. Their view of the customer would become more complex, as they would see the customer as a source of resources, and not just a load to be served by wires-side technology. The skill set of the distribution engineer may not include developing customer resources. The distribution company may have to reorganize, providing for integration customer and engineering functions.

We recognize that distribution companies in New England need to develop experience with the concept of distributed utility planning, and recommend that those utilities and their regulators consider pursuing pilot programs to advance understanding and practice in this area. In particular, they should focus on those local areas and facilities that are challenged by historic or pending growth, and where a concentration of DR resources could provide immediate value. A distribution company considering adopting this approach to distribution system planning can test the concept in a pilot.<sup>39</sup> The utility could demonstrate the concept with attention to details of process and staffing requirements, and then it can scale it up to the rest of the service area.

Regulators should examine existing policies to see how they might be improved to support deployment of low-cost customer-based resources to improve local distribution services. They should consider appropriate tariff changes to support distribution credits to customers; consider how to encourage efficient and reliable distribution services through ratemaking and performance-based regulation; consider how to support the distribution company's recruiting demand resource participants; and consider promoting the development of these innovations in pilot programs within distribution utility service areas.

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<sup>37</sup> The reality is that there is significant electricity sales growth on most distribution systems. Even if this growth in electricity service demand is offset 100% by demand resources, utility net income from sales will not be negatively affected, though it may not match historic expectations.

<sup>38</sup> These policies are described more fully in Moskovitz, et al. "Profits and Progress Through Distributed Resources," (RAP February 2000) posted at [www.raponline.org](http://www.raponline.org).

<sup>39</sup> National Grid is testing this concept in Brockton, MA. In Vermont, utilities are working with regulators on how to implement it.

## **Appendix A. Potential Added Roles and Responsibilities for a coordinated regional effort of states**

If regional planning capacity of some significance exists, there is the opportunity to address other tasks that are either not resting anywhere, or are ill-suited as they are currently organized. These are presented as opportunities requiring development, and are presented here for information.

- **Transmission Siting.** As state siting authorities review petitions for new transmission lines, an assessment of need from a regional perspective can provide a very relevant insight that is difficult to obtain today. This is especially valuable if the need being addressed, or the line itself, includes more than one state.
- **Regional Resource Adequacy.** FERC has identified the capacity market as one that merits significant reform. Its proposal in its notice of proposed rulemaking on standard market design suggests that state work as a region to make an advisory finding on the amount of excess capacity needed for the system to have sufficient reliability. FERC appears to be setting a floor for adequacy, but is trying to find ways for regions to make their own decision on appropriate adequacy levels.<sup>40</sup> Even if the ISO retains the responsibility to set a resource adequacy target, the states as a group may be able to provide valuable advice and information to improve the decision.
- **Congestion Monitoring.** New England is currently divided into eight zones for the purposes of managing congestion through pricing. As the system changes, these zones may change. The states operating together may provide insight and fortitude to the ISO to make changes to zone boundaries that have long run benefits, overcoming potential concerns of market participants with an interest in maintain existing zones regardless of their purpose and may also provide useful advice concerning whether congestion mitigating regulations are having sufficient effects to discourage mis-placed generation.
- **Market Power Monitoring.** States working together can be a foundation for state efforts to police market power. While FERC has established a significant market monitoring unit, many state officials have suggested that their own efforts will be needed to provide sufficient confidence that exercise of market power will be discouraged because it is likely to be discovered and mitigated after the fact.
- **Coordination with Gas Supply and Infrastructure.** Integration of regional electricity planning with regional natural gas planning has become essential. ISO-New England has acted on this in its recent work. Public policy trade-offs concerning the implications of increased use (and dependence) of natural gas for

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<sup>40</sup> Adequacy is used here to represent the aspect of reliability regarding having adequate capacity to meet customer demand given reasonable contingencies very nearly all the time.

electric power on reliability will be better examined in a forum for discussion that does not now exist.

- **Integration of Environmental Concerns.** Imperatives assuring a healthy environment present constraints to the power industry and its mission. Clearly identifying these constraints allows the market to account for them completely, avoiding avoidable clashes in crisis situation.
- **Technical Potential Evaluations.** In considering a category of resource, it is sometimes useful to evaluate its technical potential as a resource. States already conduct studies of energy efficiency potential, and wind potential within their borders. There is certainly some back of the envelope assessments of natural gas potential at various pipeline expansion configurations. A regional assessment of these data could add to its quality and acceptance.
- **Analysis and Support for Innovative Solutions.** Some emerging problems, such as an area of persistent growth, may be a particularly appropriate target for innovative regulatory approaches, such as intensive deployment of customer resources, or rate designs designed to influence consumption patterns. A regional assessment could identify such opportunities, provide information to state regulators about them, and assist state regulators to understand the regional implications of potential policy choices
- **Public Benefit Co-ordination.** Though drifting away from system operation, the presence of a regional cooperative effort may create the opportunity for co-ordination of state-directed efforts in energy efficiency and renewable energy that may be more efficiently deployed with a regional focus. Northeast Energy Efficiency Partnerships already acts to co-ordinate some energy efficiency programs for service providers in several New England states, and there have been suggestions that co-ordinating deployment of state renewable research and development funds would also be effective.

## Appendix B. Planning Process Example

Setting: In doing a system assessment, the fictional city of Altoid presents a concern.

While the current load/resource balance is acceptable, at loads 10% higher than current summer peak, if a major feeder were out (as it could be for maintenance), a second contingency failure (two separate generators in the area going out) would present an unacceptably high probability (still very low) that area voltage could collapse. In this situation, operators would be forced to shed load in Altoid before that happened. At present forecasts (including the effects of current energy efficiency programs), a 10% increase in load will occur in seven years. This presents an identified deficiency.

Upon identifying this deficiency, the planning process receives proposals to address this problem from transmission and generation companies. It also hears from the local energy efficiency provider through a state regulatory process that a more intensive effort (priced out to be less expensive than the generation and transmission solutions) would delay the planned 10% increase by five years. Other demand-related proposals add an additional three years, so the total demand-related package moves the forecasted “need date” from seven to fifteen years out.

Regional transmission/reliability policy provides that a transmission upgrade to address the Altoid deficiency would be recoverable in transmission tariffs. Therefore, under the efficient reliability standard, the same treatment is accorded to the non-transmission solution. With assurances that the state regulators will sign off on more intense energy efficiency services targeted at Altoid, the commitment of wholesale tariff funding is made. Because of the original deficiency, the ISO tariff would be authorized to support the cost of the demand-related measures, achieving the objective of parity among resources.

The issue of cost allocation would remain in this situation, as for the traditional transmission option. Decision-makers (e.g., ISO-New England, FERC, state PUCs) would need to assess whether all New England consumers should support these costs, or whether customers only in Altoid’s zone should pay. The *planning process* does not answer this question; the key point is that the same cost allocation rules should apply to transmission and non-transmission solutions.

Over time, the ISO can monitor the deployment of the customer resources with sufficient opportunity to raise an alarm if the solution is not operating to expectations. This is similar to the oversight expected for grid-supported generation or transmission solutions to power system deficiencies.