ISO Discussion Paper

Aligning Markets and Planning

June 13, 2012

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ISO Discussion Papers are intended to facilitate discussion of technical market, planning, and operational issues among stakeholders and ISO staff. In the event a representation herein differs from a provision of the ISO's tariff, the tariff shall prevail.

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I. Introduction and Summary

Since 2010, the ISO, New England states, and market participants have engaged in a Strategic Planning Initiative focused on the region's wholesale electricity sector.[1] The ISO launched this initiative to highlight and address both short-term risks and long-term challenges to the reliability and efficiency of New England's power system.

One of the central issues identified through this dialogue is the need to improve the alignment of markets and transmission planning. Stakeholders and the ISO have noted that existing wholesale markets do not fully reflect system reliability requirements that are identified through the region's transmission planning process.[2] When today's planning process identifies a potential future reliability problem with the transmission system, the region typically commences a cost-of-service transmission project without considering alternative, market-based solutions to the problem. An investment in new generation or demand-side resources, obtained through competitive markets, may prove a faster and superior solution.

Enabling market-based alternatives to cost-of-service transmission investment furthers an objective New England embraced over a decade ago. A central goal of the electric industry's restructuring was to permit competitive markets to bring forward the resources necessary to ensure the wholesale power system's reliability. Investment in the transmission network, by contrast, remains governed by cost-of-service regulation.[3] The concept that has prevailed in New England is that regulated transmission investment should serve a 'backstop' role in satisfying the region's reliability requirements.

As the ISO's transmission planning experience and resource adequacy markets have developed, it is becoming clear that some reliability needs presently met with cost-of-service transmission investments could, in principle, be satisfied with competitively-procured capacity resources. The question at hand is what enhancements to the ISO's markets and planning activities will facilitate turning this principle into practice.

Broadly, the ISO believes three enhancements are desirable. First, the timing of transmission planning decisions needs to be better aligned with New England's capacity market. Second, market participants need appropriate information to develop competitive market solutions that address the potential reliability concerns identified in

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[1] The ISO's Strategic Planning Initiative materials are available at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/index.html.

[2] See *Aligning Planning and Markets* (October 27, 2011), at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/2011/alignment_of_markets_and_planning_white_paper.pdf.

[3] Merchant transmission facilities, while few in New England, are an exception.

the planning process. With respect to these two issues, the central objective is to have information dissemination and the procurement of market resources timed in coordination with the regional transmission planning process. Third, and most importantly, the market should send appropriate price signals to attract private investment that could alleviate the need for cost-of-service transmission projects. To provide appropriate price signals, the capacity market must be locationally differentiated—to a greater extent than today—so that capacity resources are procured in more efficient locations.[4]

The importance of these goals is underscored by the potential retirement of a substantial portion of New England's older generating facilities. Because of both new environmental regulations and current market conditions, the ISO considers it plausible that over 5,000 MW—a sixth of the region's existing generation fleet—may permanently shut down over the coming decade. If these retirements do occur, the region will need to procure new resources to replace them. Many of these resources are situated in key locations of the grid, where their exit could lead to violations of transmission reliability criteria (such as voltage limits, or transmission line overloading). If replacement of these resources occurs in sub-optimal locations, the existing regional planning process may procure both the new capacity resources *and* trigger development of expensive transmission projects to ensure all reliability criteria remain satisfied. Improving the region's planning and markets to guide new capacity resources to locate more efficiently—where they reduce the need for expensive transmission projects—may prove a far more economical solution.

OBJECTIVES

The primary objective of aligning planning and markets is to identify and enable broader solutions to the future reliability requirements of New England's power system. This objective seeks to remedy an existing shortcoming: When today's planning process identifies a potential future reliability problem in the transmission system, the ISO evaluates cost-of-service transmission solutions without considering alternative, market-based solutions. By improving the alignment of the resource adequacy markets and transmission planning process, the ISO expects that competitively-procured capacity resources will have a greater ability to help meet these reliability requirements.

The ISO believes these challenges are best addressed through planning and market enhancements that signal the value of private investment in key locations in the grid. In that way, the enhancements would serve both near- and longer-term objectives. In the near-term, they would help New England to address challenges of generation retirements more efficiently than current rules. Over the longer-term, they would provide an improved framework to guide private investment in capacity resources as

[4] The Commission's recent order (138 FERC ¶ 61,238) requiring the modeling of eight zones in the forward capacity market is a significant step to address this issue.

New England's power system evolves and the reliability planning process identifies new requirements over time.

Approach

Capacity resources and transmission facilities are, by their very nature, heterogeneous assets that provide different services. When the region's transmission planning process identifies a potential future reliability problem, in some circumstances a transmission solution may be the only practical alternative. These circumstances may be due, for example, to specific electrical properties and requirements, the precise locations involved, or extreme cost differences between a transmission solution and any alternative.

For many locational reliability problems, however, a transmission expansion project is not the only solution. In particular, a capacity resource—if located in the right area—may be a feasible means to resolve a locational reliability concern. This should be expected if the locational reliability problems are triggered by another unit's retirement, insofar as a new (or repowered) facility at, or nearby, the same location would remove the trigger. The same may be true if the locational reliability problem emerges due to projected load growth in a particular area.

The ISO proposes to send appropriate price signals to competitively procure capacity resources in situations where a technical analysis indicates they can help resolve locational reliability problems identified in the planning process, and thereby substitute (in whole or in part) for a transmission expansion project. In this way transmission upgrade projects become a true 'backstop' solution, to be pursued if market resources are not able to satisfy a locational reliability requirement.

'Double-Duty' Benefits

The ISO's pursuit of these objectives reflects a key concern with the existing resource adequacy market design. As load grows in a particular area of the grid, or as generation retires, it may trigger *two* different reliability needs. The first is a need for new capacity resources, in order to meet the system-level installed capacity requirement. If the addition of these resources does not result in all location-specific transmission reliability criteria also being satisfied, it will trigger the second need for transmission expansion projects. The second need ensures that power can be reliably delivered to (existing or growing) loads.

In that situation, the region may effectively 'pay twice' to solve the same problem: once for capacity to solve the system-level installed capacity requirement, and once for transmission to solve any (existing or future) location-specific transmission reliability requirements. Paying twice to solve the same problem is likely to be inefficient and unnecessarily expensive for the region.

In effect, if new capacity resources are developed in the right places, they may serve a 'double-duty': First, they contribute to satisfying the system-level requirement for total installed capacity. Second, they may reduce—or prevent completely—the need for a new transmission expansion project by resolving locational reliability requirements. Harnessing market forces to develop capacity resources that serve double-duty in this way is likely to provide a more efficient solution than acquiring both capacity and transmission to meet the region's reliability requirements.

Process and Practicalities

To realize these benefits, the ISO will need to incorporate additional reliability requirements into the existing capacity market design. The additional reliability requirements will mirror the criteria identified in the regional planning process that drive the need for new transmission projects.

From a process standpoint, market rule and planning procedure changes that enable the capacity market to incorporate these reliability requirements should be developed with stakeholders at the outset. A progressively more sophisticated implementation would be built over time. The rationale for a progressive implementation is that the requisite planning studies to incorporate new locational reliability requirements within the forward capacity market will take time and resources to develop.

In pursuing a progressive implementation, the ISO expects to focus its effort on reliability concerns that offer the largest potential benefits from procuring capacity resources as alternatives to transmission projects. These include situations due to potential generation retirements, where new resources may provide double-duty benefits: If retirements prompt new capacity resources to enter at, or near, the same locations, the need for transmission expansion projects may be greatly reduced. [5] Recent planning studies have suggested other high potential-benefit situations. This can occur when transmission solutions involve rebuilding long lines to distant load areas at high cost, but a viable alternative may be to add a small amount of capacity at the distant load area—perhaps for a fraction of the cost.

[5] Accordingly, the ISO has commenced a transmission assessment to identify, prospectively, areas where generation retirements may prompt locational reliability problems. See *Strategic Transmission Analysis Update* (December 13, 2011), at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2011/dec142011/strat_trans_analysis.pdf, and *Strategic Transmission Analysis Update* (March 15, 2011), at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/mar142012/strat_trans_analysis.pdf.

MAIN ELEMENTS

To bring this concept to fruition will require significant effort on the part of the ISO and stakeholders, and changes to both the region's transmission planning process and the forward capacity market. The main elements addressed in this paper fall in three broad categories:

► **Aligning Timing and Decision-Making.** The timing of decision-making in the regional planning process and resource adequacy markets is not well-aligned. Their misalignment prevents information produced in one venue from being effectively incorporated into the other. Enhancements to each process are desirable to ensure that (1) market participants have information on locational reliability needs in time to develop market alternatives, and (2) competitive market alternatives are procured, if available, prior to incurring significant development costs for a transmission solution.

Achieving these enhancements will require the region's transmission planning process to look farther into the future than today when evaluating system needs. To be fully effective, the ISO will need to proactively assess locational reliability issues that may be precipitated by a generator's possible exit, rather than continuing today's reactive approach to assessing the reliability consequences of generation retirements.

The timing alignment problems present today are discussed in detail in Section II.B, and potential changes to resolve these problems are described in Section V.A.

► **Providing Information on Market Resource Requirements.** The ability of capacity resources to substitute for a transmission project will vary with locations and situation-specific circumstances. To provide clear guidance to the marketplace, the regional planning process will need to evaluate and clearly describe the feasibility and specific requirements of capacity resources to help solve (or prevent future) locational reliability problems. An ISO-driven stakeholder process will be essential to convey, discuss, and vet the planning process results.

The rationale for, and objectives of, this assessment process are described in Section II.B. At a minimum, the process would assess the area(s) and total MW of capacity resources needed to substitute for (or substantially reduce the scale of) a transmission project. Additional technical requirements may be required of these capacity resources. Section IV of this paper provides the key technical foundations for these requirements, and Section V.B presents examples and discusses implementation issues.

This informational process to identify market resource requirements should run concurrently, and be coordinated, with the transmission solutions studies. Information must be provided early enough in the planning process to enable market participants to propose capacity resource solutions, for the ISO to procure them in a forward capacity auction, and for the region to ensure the solution (whether a market solution or backstop transmission) is in service prior to the year it is needed.

► **Changes to the Forward Capacity Auction.** While the basic structure of the Forward Capacity Market (FCM) would remain similar to today, many enhancements would be necessary. The purpose of these changes is to ensure that the market will provide private investors with the price signal to develop new resources that meet locational reliability needs.

First, the FCM will need to incorporate transmission security requirements, at a more granular level than today, in order to signal the value of locating capacity where it contributes to both system-level and locational reliability requirements. Ideally, the same transmission security constraints that are identified in the planning process and drive the need for transmission solutions should be modeled—prospectively—in the FCM. Since it is not practical to model all transmission security constraints, the ISO will add these constraints as part of the progressive implementation strategy with a focus on areas of greatest potential benefit.

Second, changes to the clearing mechanism of the Forward Capacity Auction (FCA) would be needed. Specifically, the FCA would need to set more granular locational prices than today, to ensure that clearing prices provide appropriate incentives for, and reflect the value of, locating capacity resources where they help resolve locational reliability problems.

It is worth noting that certain types of locational reliability constraints cannot be readily accommodated by the ISO's current capacity auction clearing algorithm. It could require the ISO to drop the existing descending-clock auction format and adopt a new auction clearing engine, based on a sealed-bid auction format. This latter change may not be necessary initially, but would become important if more complex locational constraint patterns are modeled in the FCA.

The rationale for these FCA changes is discussed in Section II.B and Section III. A more detailed discussion of FCA design impacts is provided in Section V.C.

Issues and Challenges

Executing these market and planning process enhancements presents a number of issues and challenges. Several merit highlighting here.

First, assessing the suitability and requirements of capacity resources to solve locational reliability problems in different circumstances will place substantial new burdens upon the regional planning process. Depending on the scope of this activity, these assessments may be resource-intensive for the ISO and, as an extension of the regional planning process, become a time-consuming stakeholder process. Further, the regional planning process will need to identify potential reliability problems farther in the future than today, in order to accommodate the time required to identify whether market resources are viable substitutes for a transmission solution.

Second, there are numerous technical issues to be addressed. Like the transmission planning process today, evaluating the requirements of capacity resources to substitute for transmission solutions will necessitate developing a set of guidelines that embody trade-offs between complexity, transparency, and potential benefit. We describe these trade-offs in considerable detail in Section V.B. With respect to the FCA, simple locational reliability constraints require modest changes, but more complex locational reliability constraints require more substantial changes. While the changes to the FCA may be a one-time effort, they would require modifications to the Market Rules as well as to the ISO's software systems for clearing the capacity market's auctions.

Last, procuring capacity resources as a substitute for transmission projects poses potentially difficult issues of cost allocation. The costs of regional transmission projects are allocated to transmission providers; the costs of capacity resources are allocated to load-serving entities. Moreover, if an existing local capacity zone clears at a higher price than capacity prices elsewhere in the system, the additional expense is largely allocated locally, not regionally. These rules imply that if new capacity resources are cleared in particular locations—as substitutes for pool-supported transmission projects—there may also be a significant shift in *who* bears the cost. Unfortunately, this means that current cost allocation rules do not align (*i*) an individual market participant's private interest in minimizing its allocated costs with (*ii*) society's broader interest in selecting the most cost-effective solutions. Identifying a satisfactory resolution to this controversial issue may require extensive stakeholder discussion.

THIS PAPER

This paper is a conceptual design document. As such, it does not provide answers to all the challenges the region will face in addressing reliability risks over the coming decade. Nor is it a comprehensive vision for the long-term evolution of New England's resource adequacy markets.[6] Rather, the aim is to facilitate informed discussion about options available to the region, and the technical constraints that solutions must accommodate, in order for the potential benefits of aligning planning and markets to be achieved. The ISO expects that, like system planning generally, improving the alignment of planning and markets will involve extensive discussion and collaborative problem-solving with the region's stakeholders.

The paper is organized in two major parts. Sections I through III provide an overview of the key concepts, problems and their root causes, and the implications for the region's reliability needs. These sections draw out the key risks the region faces in greater detail,

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[6] For a broader overview, see *Roadmap for New England: A Proposal for Meeting the Challenges Identified in the Strategic Planning Initiative* (March 23, 2012), at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/strategic_plan_initiative_roadmap_march_2012.pdf.

and why the ISO believes it is important for the region to pursue markets and planning enhancements to address these risks.

The second part of this paper, comprising sections IV through VI, delves into solution elements and design issues. Section IV provides technical background on locational reliability requirements, covering the foundation for how capacity resources substitute for transmission solutions—and circumstances in which they cannot. Section V explains several key solution elements, including aligning timing and information flows between markets and planning, alternatives analyses, and FCA changes. Section VI discusses several additional key issues, including cost allocation.

II. PROBLEMS AND CAUSES

Resource adequacy markets are intended to produce cost-effective investment in the power system. In this section we explain how the region's current transmission planning process and resource adequacy markets are misaligned, and why this misalignment impedes cost-effective outcomes. We begin with a more precise discussion of the problems.

A. PRACTICAL CONCERNS

The misalignment of planning and markets arises from both structural features of the transmission planning process, and limitations of the existing forward capacity market. We first address the generation retirement problems of near-term concern, and their potential consequences.

As noted in the Introduction, the New England region faces the possibility of significant generation retirements by the end of the decade. Table II-1 (*next page*) provides summary statistics for selected coal-fired and oil-fired steam generating units that the ISO considers 'at risk' for permanent shutdown over this period. Many of these units face potentially significant new capital expenditures to comply with pending federal environmental regulations. These regulations include, most importantly, the EPA's Utility Air Toxics rule (Clean Air Act §112(d)) and new cooling water intake and wastewater treatment requirements (Clean Water Act §316(b) and §304, respectively). The Air Toxics rule has a nominal compliance deadline of 2015 (with case-by-case one year extensions possible), and the cooling water rule has a projected compliance deadline that may extend to 2020.[7]

In addition, as Table II-1 indicates, the oil-fired units have low annual capacity utilization factors and therefore little energy market revenue. As a consequence, it may be difficult for their owners to justify the capital expenditures necessary to meet increasingly tighter environmental regulations and ongoing operating expenses to remain commercially viable. The ISO notes that some of the coal units have previously invested in equipment necessary to comply with (some of) the pending EPA regulations;

[7] For additional details, see *2011 Northeast Coordinated System Plan* (May 31, 2012), pp. 39-55, at http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/ncsp/2011_ncsp.pdf, and *Strategic Planning Issues* (March 4, 2011), Appendices A, B, and references therein, at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/2011/sp_npc_presentation_from_march_mag.pdf.

Table II-1. Selected Generation 'At Risk' for Possible Retirement

Type	Number of Units	Average Age	Capacity (MW)	Capacity Factor (2011)
Coal-Fired	10	47	2355	31.3%
Oil-Fired (Steam)	12	44	2661	0.9%
All	22	45	5016	

Notes: Excludes all Salem Harbor units. Capacity is Summer SCC value as of Jan 1, 2011. Capacity factor is calculated using metered net energy and available capacity across all units within each group.

and a portion of the oil-fired units listed in Table II-1 could be converted from oil to natural gas as their primary fuel, at a cost. As a result, it remains uncertain at this time how many of these 'at risk' generating units will continue to operate past 2020.

IMPLICATIONS

If a large share of the units summarized in Table II-1 were to retire, it would have two significant impacts on reliability planning in New England. One impact is obvious, the other less so.

First, retirements on this scale would trigger a need for new capacity resources in order to achieve the system-level installed capacity requirement. As the ISO has previously indicated, based in part on the current interconnection queue, it anticipates new capacity additions in New England will be a combination of high-efficiency natural gas-fired generation, demand-side resources (especially energy efficiency), and additional renewable resources (primarily wind).[8] An important observation is that under current market rules and incentives, these new resources are likely to locate in different places than where the retiring generators are located.

The second, less obvious impact of these retirements is on locational reliability conditions in the New England transmission system. Many of the generating units in Table II-1 are located at critical points in the transmission network. These units were constructed by New England utilities, prior to competitive wholesale markets, who built the transmission system around them. Retirement of these units may trigger violations of location-specific transmission reliability criteria, such as transmission line voltages outside of admissible limits during high load conditions, post-contingency transmission thermal overloads, and so on, if these resources are replaced in sub-optimal locations.

EXAMPLE

A recent case in point is the retirement of the Salem Harbor generating station. Salem Harbor is a 50+ year-old coal- and oil-fired plant located north of Boston. Its owner proposed in 2011 to shut the facility (via a "non-price retirement bid" bid in the forward capacity market) in 2014. The ISO, as part of its review for potential violations of locational reliability criteria, determined that a complete shutdown of the facility would not result in a resource adequacy deficiency for New England overall; however, it would result in violations of transmission reliability criteria (thermal overloads) in the area

[8] *Strategic Planning Issues, op cit.,* p. 6-9.

under certain line-out conditions during high system loads.[9] The ISO and the area transmission owner identified a set of transmission line upgrades to resolve these reliability concerns prior to the facility's anticipated shut-down in 2014.[10] Retaining these (or repowered) units at this location was not studied by the ISO, as the facility owner elected to retire the plant.

CONSEQUENCES

Under existing practices, transmission upgrade projects would be undertaken to resolve potential violations of location-specific transmission reliability criteria prompted by a generator's exit, provided there is sufficient generating capacity in the system overall. The ISO, through the regional planning process, documents the locational reliability problem; the transmission owner serving the area is then obligated to build a transmission solution to address the reliability problem. In the interim, the unit that seeks to retire may be prevented from doing so for a period of time, and paid above-market compensation while the transmission project is underway.

This practice works well at preventing locational reliability problems from becoming manifest. However, this practice may not satisfy the broader objective of promoting cost-effective investment in the power system. There are several reasons. First, when a unit retires, a potential locational reliability problem can be ameliorated through at least two means. One is a transmission upgrade project, provided there is sufficient generating capacity elsewhere to replace the retiring resource. Alternatively (or in combination), a new capacity resource located in, or near, the same area may be able to maintain local reliability.

The problem is that if a private entity elects to develop a new capacity resource, there is little incentive to locate the resource where it would solve the locational reliability problem. Energy markets provide locational price signals for network congestion, but many locational reliability needs (*e.g.,* voltage support) are not signaled via network congestion.[11] The existing local source requirement zones in the forward capacity market are few and are coarse, in the sense that they reflect only a few of the many locational reliability (transmission security) constraints honored in the planning process. The effect of these shortcomings is that the capacity market does not signal, with

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[9] *Salem Harbor Reliability Need Determination*, Rev. 1 (May 5, 2011), at http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/relblty/ceii/ceii_mtrls/2011/may92011/a3_salem_harbor_npr_report_rev1.pdf [CEII].

[10] National Grid, *Proposed Plan Application – North Shore Reconductoring Project* (June 29, 2011), at http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/relblty/ceii/ceii_mtrls/2011/jul26272011/a13_1_northshore_115_reconductor_lvl1_ppa.doc [CEII].

[11] For example, voltage support requires reactive power supply, which is paid on a cost-of-service basis under the ISO Tariff and is not priced in the day-ahead or real-time energy markets. Other out-of-market operating requirements (e.g., local contingency protection commitments) may produce NCPC ("uplift") costs, which are not transparent to the market.

adequate specificity, the places for capacity resources to locate in order to solve the system's locational reliability constraints.

TRANSMISSION PLANNING AND MARKET RESOURCE ALTERNATIVES

The benefits of aligning markets and planning along these lines are not limited to events associated with generation retirements. Rather, they extend to the regional system planning process generally.

The ISO, as part of an open regional planning process, forecasts changes in loads and system conditions ten years forward and models whether these changes may impinge upon system-level and locational reliability criteria. If resources are adequate at the system level, but generation cannot be delivered to (projected) load in any area of the system while honoring all transmission limits, the planning process will identify the need for a transmission system upgrade.

To date, this process has worked well at preventing violations of transmission planning criteria. As with situations prompted by generation retirements, however, this process makes no effort to identify whether competitively-procured generation or demand-side resources could solve the same problem.

DOUBLE-DUTY BENEFITS

A key observation is that, if these locational investment problems were solved efficiently, new capacity resources may effectively serve a 'double-duty'. To put this in perspective, note that when new capacity is needed, current transmission planning and cost-recovery mechanisms may have consumers 'paying twice' to ensure reliability: Once to acquire new capacity that meets the system-level resource adequacy requirement, but with capacity resources that—under current rules and incentives—may choose to locate sub-optimally in the network. The second time is to upgrade the transmission network, in order to solve any (existing or future) transmission security problems delivering power to load from sub-optimally located generation.

In contrast, if new capacity resources are located at the right places on the transmission system, these resources could contribute to the system-level capacity requirement *and* avoid the need for new transmission projects to satisfy location-specific transmission reliability criteria. That is, new capacity in the right places serves double-duty by contributing to both the system-level resource adequacy requirement as well as locational reliability requirements. Providing the incentives and information that lead new capacity resources to locate where they contribute to both sets of reliability requirements—and reduce the expense of additional transmission—is likely a more efficient investment solution.

In this paper, we use the term *market resource alternative* ('MRA') to refer to a capacity resource that can substitute for a transmission project to address a location-specific transmission reliability concern. The term is generic, insofar as an MRA may refer, in principle, to either a generation facility or a demand-side resource. As the preceding discussion suggests, the benefits of an MRA may be precipitated by generation retirements, by load growth, or other factors identified in the regional transmission planning process.

EXAMPLE

Apart from generation retirement situations, the recent New Hampshire/Vermont planning studies suggest conditions with high potential benefit from MRAs. When load is projected to grow in an area that is distant from existing generation, transmission solutions to deliver additional power to the area may involve rebuilding or reconductoring long transmission lines, at high cost.[12] The ISO conducted a pilot study to investigate whether new capacity resources (MRAs) located near areas with locational reliability concerns in New Hampshire and Vermont could help resolve these concerns. Under the idealized (modeled) conditions of the pilot study, the answers are generally affirmative.[13] In addition, demand-side capacity resources (in the form of energy efficiency projects) in certain areas have deferred the need for transmission upgrades, while ensuring all reliability criteria are met.[14]

B. ROOT CAUSES

To enable market-based alternatives to cost-of-service transmission projects, several aspects of the planning process and resource adequacy markets will require changes. To guide discussion of the scope and nature of these changes, it is helpful to have a more precise understanding of the root causes.

There are three root causes of the misalignment problem. In brief, these are:

1. *Insufficient Technical Information.* There is no mechanism to assess and provide markets with information on the locations, quantities, and other technical requirements of capacity MRAs that may substitute (in whole or in part) for a transmission project.

[12] See *New Hampshire/Vermont Transmission Solutions Study Report* (April 13, 2012), Tables 7-1, 7-2, 7-7, and 7-10, at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/reports/2012/nhvt_solutions_report.pdf [CEII].

[13] *Nontransmission Alternatives Analysis – Results of the NH/VT Pilot Study* (May 24, 2011), p. 16-20, at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2011/may262011/nta_analysis.pdf [CEII].

[14] Recent updates to the New Hampshire/Vermont studies lowered projected net loads in certain areas due to energy efficiency impacts, and deferred the year of need for transmission upgrades. See *Follow-up Analysis to the New Hampshire/Vermont Solutions Study* (March 9, 2012), at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/reports/2012/nh-vt_solutions_follow-up.pdf [CEII].

2. *Incentives.* The existing zones in the resource adequacy markets are few. These zones are generally too coarse to provide an incentive for market participants to develop new resources where they may substitute (in whole or in part) for a transmission solution.

3. *Timing of Information and Decision-making.* Neither the timing of the information produced, nor the timing of decision-making, in the planning and resource adequacy processes is well-aligned. This prevents essential information produced in one venue from being incorporated into the other.

We explain each of these three root causes, and their implications, in turn.

Root Cause 1: Uncertain MRA Requirements

The first root cause is that presently no mechanism exists to assess and supply markets with information on the locations and technical requirements of an MRA that may substitute for a transmission upgrade project. This root cause involves two conceptually distinct components that are missing today:

(1) *MRA Technical Analysis.* Analysis of what locational and technical requirements would be sufficient for a capacity resource to be capable of solving (in whole or part) a specific locational reliability problem; and

(2) *Information Provision.* The provision of these locational and technical requirements, in a timely way, to the marketplace so that participants can develop capacity MRAs to the transmission project.

Technical Analysis

The first component is essential because transmission, generation, and demand-side resources are inherently heterogeneous products. Moreover, locational reliability problems take several different forms (such as thermal limit violations on transmission lines, voltage support requirements, and so on). Because of this variation in both needs and resource types, considerable analysis may be required to identify what attributes of a MRA are necessary to help solve a locational reliability problem in different circumstances.[15]

For example, the need to analyze such requirements arises in cases involving generation retirements that trigger potential violations of transmission reliability criteria. Here a key issue is how many megawatts of new capacity would be needed, and in what locations, in order to satisfy both the system-level resource requirement *and* eliminate the need for a transmission upgrade project to address a locational reliability problem. In general, resolving a locational reliability problem may require fewer megawatts of capacity than the retiring facility, and could be interconnected at a larger set of network nodes.

[15] Generation MRAs will also (typically) require some transmission investment to interconnect and meet deliverability tests.

For some locational reliability problems, the requirements of an MRA may be greater than just location and capacity. For example, for locational reliability problems requiring transmission voltage support, a MRA also needs to be capable of supplying reactive power into the grid. Some types of capacity resources can do this; others cannot.

We discuss these locational reliability requirements in greater detail in Sections IV and V.B, where we expand on the implications for MRAs to substitute for transmission upgrade projects. The technical nature of locational reliability requirements, known more precisely as *transmission security* constraints, is important because they inform the scope and feasibility of MRAs in different circumstances.

INFORMATION PROVISION

The second component noted above is the provision of the locational and technical requirements to the marketplace, with adequate time for market participants to develop MRA proposals that meet these requirements.

Without information characterizing the required location(s), capacity, and any other technical requirements, a competitive market will not be able to develop capacity resources in the most effective locations—nor produce MRAs that are viable substitutes for a transmission reliability project. At present, there is no systematic process to assess and provide this information to New England's market participants.

ROOT CAUSE 2: INCENTIVES

The second, and most significant, root cause is one of incentives—or, more precisely, non-aligned incentives. The crux of the incentive problem is that no mechanism presently guides capacity resources to locate in the precise areas where they would prevent (or resolve existing) locational reliability problems. The FCM's existing local source requirement areas are coarse, in the sense that they do not reflect many reliability (transmission security) constraints that are important in transmission planning decisions.

Capacity resources cost more to develop in some locations, such as near load centers, and less to develop in other places in the system. Because a capacity resource may contribute to system-level resource adequacy as well as solve a locational reliability problem if located in the 'right' place, capacity may be considerably more valuable (from a reliability standpoint) if located in fairly specific areas of the transmission system. In the absence of appropriate locational price signals, market resources' incentives are to locate where their costs are minimized, not where they minimize the region's costs of ensuring a reliable power system.

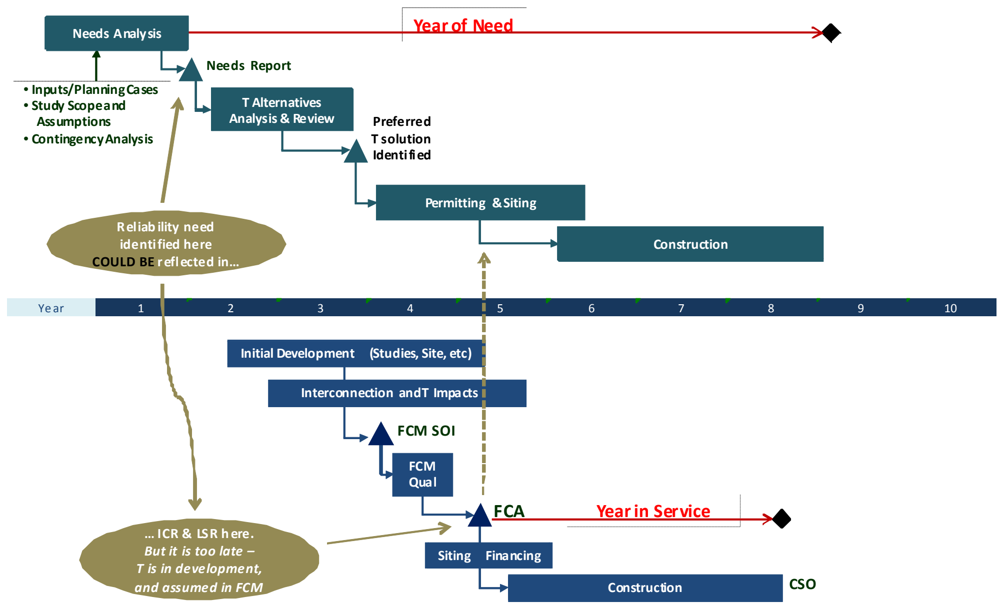

Figure II- 1. Current transmission planning and FCM timelines.

The absence of adequate locational price signals and market incentives for capacity resources to locate in the most efficient places is, in some respects, the principal misalignment between planning and markets. Without a solution to this incentive problem, the other changes to planning and markets are unlikely to produce competitive alternatives to cost-of-service transmission solutions.

Root Cause 3: Timing and Information

The final root cause is procedural. The transmission planning process and the resource adequacy markets proceed on different timeframes. This is primarily a problem of *information flows,* in that existing timeframes prevent essential information produced in one venue from being incorporated into the other.

Two Timing Issues

There are two specific timing issues. Suppose first that Root Cause 1 is addressed through the development of an open, ISO-driven process to evaluate the situation-specific technical requirements of MRAs. For that process to be effective and informative, it must be completed well in advance of the resource adequacy qualification process; markets need information on the locational (and other) requirements of MRAs early enough to propose feasible capacity projects.

The second timing issue arises after the resource adequacy market clears, and reveals whether sufficient MRAs are procured to avoid (or reduce the scale of) a backstop transmission project. This must occur before significant costs are incurred to develop a transmission solution to a reliability problem. The present timing of the transmission planning process does not look sufficiently far into the future to accommodate this sequencing requirement.

These two timing problems are illustrated graphically in Figure II-1. The top portion of the figure shows a typical timeline for the current transmission planning process, which looks forward over a planning horizon of approximately a decade. While the actual later-stage permitting and construction phases vary widely in duration, the focus of present concerns is with the decision process in years 2 through 5.

► **Timing Issue 1.** The first issue is when MRA technical information is available to market participants. In order for the resource adequacy markets to develop MRAs to an identified locational reliability problem, the markets would need information on the MRAs requirements by the end of year 3. That would require the MRA technical assessment process to be complete at about the same time the preferred transmission solution alternative is identified.

► **Timing Issue 2.** The second issue is the timing of the FCA in which MRAs are procured, relative to the timing of the transmission development decision. Suppose that the MRA assessment process is complete at about the same time a preferred transmission solution alternative is identified, as shown in year 3. The next FCA for which the qualification process occurs *after* the end of year 3 is in year 5 (see Figure II-1).

This implies that by the first opportunity for the resource adequacy market to procure MRAs, we are already in year 5 of the planning horizon. The problem is that by this point in time, a decision on the final transmission solution may have been made more than a year earlier—and already incurred significant permitting and siting costs.

IMPLICATIONS

The timing of the existing markets and planning processes needs to be modified, in two key respects, in order to accommodate essential information flows between each process. One is to complete the MRA requirements process well before the qualification process for MRAs that wish to be considered in the resource adequacy market's selection. The second is to seek to procure these MRAs in the forward capacity market before incurring significant transmission solution development costs (such as permitting and siting).

These timing issues increase the importance of conducting transmission needs assessments to identify potential future locational reliability problems at an early stage. We discuss these timing issues, and how they may be resolved, in greater detail in Section V.A.

III. Implications and Objectives

The preceding discussion of root causes indicates the problems that must be overcome to enable market resource alternatives to cost-of-service transmission projects. Before proceeding to discuss key solution elements, however, it is useful to draw the implications of these root causes to a point.

Objectives

At this paper's outset, we noted a broad goal of the ISO's Strategic Planning Initiative is to improve the alignment of planning and markets. With the preceding discussion as context, we can productively reframe this broad goal in terms of more specific objectives.

► **Objective.** The primary objective of aligning the regional planning process and resource adequacy market is to enable competitive markets, to the extent feasible, to bring forward the resources necessary to solve both locational and system-level reliability requirements. In so doing, cost-of-service regulated transmission projects serve a true backstop role, to be pursued when market resources are unable to meet the region's reliability requirements.

In many respects, this objective is not a new direction for the region, but rather an enhancement to the region's decade-long embrace of competitive markets as the primary means to assure the reliability of New England's power system. The enhancement seeks to remedy an existing shortcoming: When today's planning process identifies a potential future reliability problem in the transmission system, the region typically commences a cost-of-service transmission project without considering alternative, market-based solutions at all. By improving the alignment of markets and planning, the ISO expects that competitively-procured capacity resources will have a greater ability to help meet these reliability requirements.

► **Approach.** The ISO's preferred means to achieve this objective is to enhance the forward capacity market, so that it provides more efficient market signals for private investment in key locations in the grid. The rationale for this approach is to spur new entry (and avoid inefficient exit) of capacity resources when and where they are able to meet the region's combined locational and system-level reliability requirements.

The ISO expects this approach will have two effects. First, it creates greater incentives for new capacity to enter, and existing capacity to remain, in areas where it is most valuable from an overall reliability standpoint (that is, where it addresses both transmission security and system resource adequacy). Second, this will reduce the incentives for new capacity to enter, and existing capacity to remain, in areas where it contributes the least to reliability. Over time, both effects will reduce the region's reliance on backstop transmission upgrades as the sole, non-competitive solution to locational reliability problems.

► **Focus.** The ISO expects its implementation effort to focus on situations with the largest potential benefits from procuring capacity MRAs to transmission projects. It will not be practical for the ISO to model, within the forward capacity market, every transmission security constraint examined in the ISO's transmission planning studies. However, modeling all such constraints in the FCM is not necessary to improve planning and markets' alignment. As we explain in the following sections of this paper, modeling key constraints in the FCM will provide a sound foundation and practical method for establishing price signals that enable and appropriately reward market resources for entry and meeting identified reliability needs without (or with less) cost-of-service transmission development.

Of particular importance are the cases prompted by potential generation retirements. Here the ISO expects capacity MRAs to provide afore-mentioned double duty service: Not only would they satisfy a potential need for capacity resources to maintain the system-level resource adequacy requirement, but they can reduce the need for backstop transmission projects to address locational reliability problems resulting from key generation retirements.

Other candidate situations may involve cases like those suggested by the ISO's New Hampshire/Vermont pilot study of MRAs (discussed in Section II.A), where transmission solutions may require rebuilding long lines that would be expensive—but the additional capacity required with an MRA solution may be only a small number of megawatts in the right area of the system.

IMPLICATIONS

What would a capacity market look like that achieves these objectives? The capacity market would need to incorporate additional transmission security constraints, at a more granular level than today, in order to signal the value of locating capacity where it contributes to both system resource adequacy and locational reliability requirements. Ideally, the same transmission security constraint(s) that are identified in the planning process as the drivers of the need for a transmission project would be modeled in the FCM. Such constraints are economically important if they bind in the FCA, which sends locational price signals to the capacity market. By doing so, the FCM would set more granular locational prices than today, providing incentives for resources to locate where they can solve (or prevent future) locational reliability problems.

Both of these features are conceptually analogous to the existing local source requirement (LSR) constraints in the forward capacity market. The differences are primarily, though not entirely, matters of extent. The existing LSR areas are few, and far too coarse to accurately signal the value of locating capacity in many areas of the transmission system. Resolving this would require modeling local reliability (i.e., transmission security) requirements in the FCM with greater specificity, as well as procedural changes to timing and decision-making.

The balance of this paper discusses the changes needed to achieve these objectives in greater detail. At a broad level, the changes can be summarized with reference to each of the three root causes described previously:

- *MRA Technical Analysis.* This involves assessing whether MRAs are technically capable of substituting for a transmission project in order to solve an identified locational reliability problem; determining the area (set of nodes) and MW required in order for capacity resources to eliminate or reduce the need for the transmission project; and identifying any other technical requirements of MRAs in different circumstances. This step addresses Root Cause 1.

- *Incorporating the capacity required to solve the reliability problem as a constraint in the FCA.* This enables the FCA to reveal the least-cost MRA solution, and procure capacity resources as MRAs in the amounts and locations needed. This requires more granular locational pricing of capacity than today, to ensure that clearing prices provide appropriate incentives for, and reflect the value of, locating capacity in more efficient places. This addresses Root Cause 2.

- *Timing of decision-making.* To implement this requires the ISO to modify the timing of the markets and planning processes. The modifications are needed to ensure that (1) markets have information on MRA technical requirements early enough to develop alternatives, and (2) the results of the FCA are available prior to incurring significant development costs for a transmission solution. Moreover, the former will require the ISO to proactively assess locational reliability issues that may be precipitated by a generator's decision to exit. These timing changes address Root Cause 3.

As a practical matter, there are many details to address regarding each of the three elements summarized above. We take up each of these elements in detail in Sections IV, V, and VI, next.

IV. CONSTRAINTS

The ISO's transmission planning process centers on anticipating potential reliability concerns before they develop, and understanding situations in which they may be created. In precise terms, these reliability concerns are known as *transmission security* requirements. Transmission security requirements determine why capacity has greater value in some locations than in others. They also play a central role in determining the scope and feasibility of MRAs in different circumstances.

In this section, we discuss the nature of transmission security requirements and their implications for MRAs. The purpose of this discussion is twofold. The first purpose is to clarify the relevance of transmission security requirements to the locational value of capacity resources. These locational values should be appropriately signaled in the resource adequacy markets. The second purpose is to articulate how and why MRAs can satisfy some transmission security requirements, and not others. These considerations are important determinants of how the ISO implements MRAs.

A. RELEVANCE

Transmission security requirements, although technical in nature, are the logical foundation for locational capacity markets. In broad terms, transmission security is why the regional planning process identifies a need to add transmission 'here', not 'there'. If capacity resources are evaluated as potential substitutes for a transmission project, the planning process may similarly find that capacity must be added 'here', and not 'there', to satisfy these transmission security requirements.

The implications of transmission security constraints for MRAs, as analyzed in the planning process, are therefore substantial. They may indicate where MRAs must be located, how many megawatts are required, and why. As these transmission security requirements are incorporated into the clearing mechanism of the FCM, they effectively determine how much more must be paid to attract capacity resources in one area (where they would help resolve a locational reliability constraint) than in another area (where they would not).

SIMPLE EXAMPLE

A simple example illustrates these points. Consider the hypothetical transmission network shown in Figure IV-1. Each solid line is a transmission link, the circles represent generation locations, and the triangles represent load centers. Two areas, East and West, are separated by an interface (dashed line) consisting of three transmission lines.

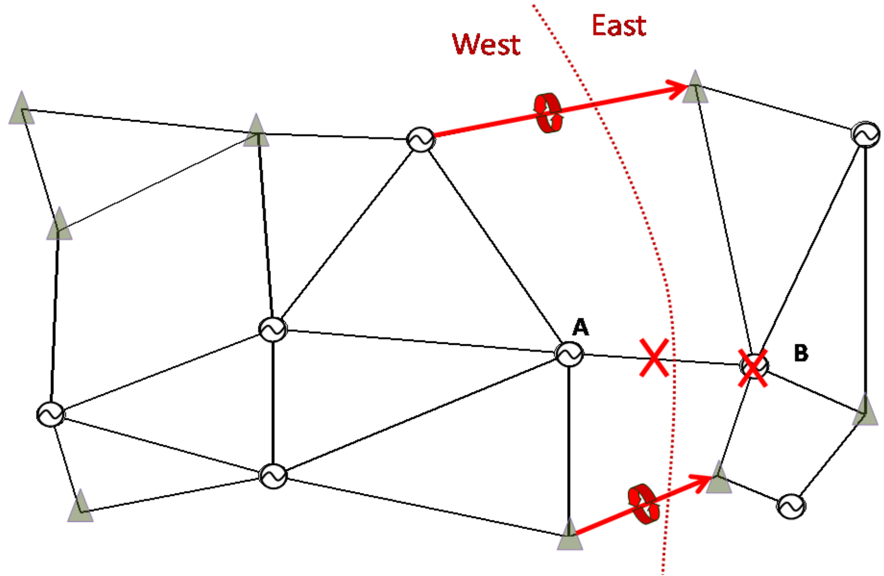

Figure IV- 1. *A hypothetical network. Additional capacity in the East reduces overloads on the red lines, if Line A-B and Generator B are out of service; additional capacity in the West does not.*

Suppose that, in the planning process, the East area is projected to experience load growth that cannot be satisfied under certain system contingencies. Specifically, if the generator at B is out of service under high load conditions, then if any of the three transmission lines across the interface fail the other two lines would be overloaded and the ISO would be unable to meet demand in the East. The planning analysis might indicate two possible solutions: (i) upgrade the transmission capability across the interface; or (ii) increase the megawatts of capacity resources located in the East.

Suppose further that there is 1800 MW of existing capacity in the East, and that a total of 2000 MW would be needed to eliminate the need for the transmission upgrade. Then 200 MW of capacity resources are more valuable, at the margin, if located east of the interface than if located west of it.[16]

In sum, capacity in the right amounts and locations is valuable because it may satisfy the system's transmission security constraints while enabling New England to avoid a transmission project; capacity in the 'wrong' areas is less valuable, because it may not do either.

IMPLICATIONS

The basic point here is straightforward. The line-level and interface-level analyses of transmission security requirements help determine (i) where MRAs must be located; (ii)

[16] This property assumes, as we do here, that adding 200 MW of capacity resources affects only a single, one-directional transmission security constraint. If there are bi-directional constraints, or multiple (overlapping) constraints, the determination of locational capacity values becomes more complex. See Section V.C.

the quantity of capacity in an area required to substitute for the transmission project; and, in large part, (iii) the relative value of this capacity, from a reliability standpoint (that is, relative to other locations in the system). In application, however, there are many details that enter into these analyses, and the results will generally depend on the specific type of transmission security requirement at issue. We elaborate on the essential details, and their implications for MRAs, next.

B. Details and Implications

In order for a Market Resource Alternative to be an effective substitute for a transmission project, the MRA must be able to help resolve the same underlying transmission security problem as the transmission project. In this section, we describe several specific types of transmission security requirements analyzed in the planning process, and their implications.[17] The purpose of this discussion is to clarify the technical basis for how and why these requirements may be satisfied with a capacity resource, and why capacity has higher value in certain locations than in others.

The discussion also highlights the need for the ISO to evaluate situation-specific information in order to determine the locational and technical requirements an MRA may need to satisfy. A particular MRA may—or may not—be a viable substitute for a transmission project to resolve a specific transmission security constraint. In addition, some types of transmission security constraints will necessitate specific technical requirements of a MRA.

Transmission Security Requirements

A central objective of the region's transmission planning process is to forecast electricity demand and infrastructure conditions at least a decade hence, and evaluate whether the transmission system is adequate to deliver power from where it is produced to where it is consumed. In practice, 'adequate' requires honoring several different transmission requirements. Specifically, the ISO's planning engineers examine three types of transmission system limits:

- Thermal overload limits
- Voltage tolerance limits
- Stability limits

Collectively, these limits on how much power may flow across a given component of the transmission system are known as *transmission security constraints*.

[17] ISO transmission planning is based on criteria and standards established by NERC, NPCC, and ISO New England Inc. This non-technical summary simplifies that process.

THERMAL LIMITS

In many respects, *thermal limits* are the simplest type of transmission security constraint to resolve with additional generation or load-modifying resources.

The physical basis for thermal limits is that, as electrical power flows across the transmission system, a fraction of that power dissipates in the form of heat. Transmission equipment is designed to handle this, but there are limits: An excessive power flow generates excessive heat, which can cause the line conductor to sag or anneal and suffer permanent damage. In practice, each transmission network component has ratings that indicate the amount of power (in MW) the component is designed to handle, under normal conditions and in emergency situations.

PLANNING PROCESS

In the transmission planning process, the ISO assesses possible future load growth and changes in generation resources on the system, and how that will affect the flow of power across each component of the transmission system. The analyses evaluate whether the power system can be dispatched, under a wide variety of scenarios, without exceeding the ratings on each transmission system component. Such analyses can reveal if different types of infrastructure investment—whether in transmission, generation, or load reduction—can resolve a thermal overload problem.

EXAMPLE

A simple example illustrates the process. Figure IV-2 shows a portion of a hypothetical system in which there is both generation and load at Location A. Location A is connected to the rest of the regional transmission system by two parallel transmission lines, Line 1 and Line 2. Each of the two lines line has a thermal limit of 100 MW. The generator at A has a capacity of 50 MW.

Imagine that over a 10-year planning horizon, the ISO plans for a peak load at A of 120 MW. The transmission planning process would then check, among other things, whether this load can be served if any one element of the power system is out of service. In this instance, the answer is yes: If either Line 1 *or* Line 2 is out of service, the other (in-service) line, in conjunction with the generator at A, are able to deliver a total of 150 MW of power to the 120 MW load at A.

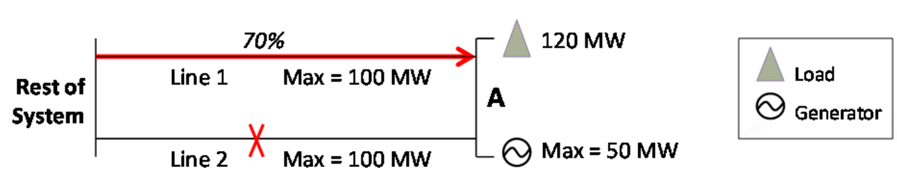

Figure IV- 2. *A peak load at A of 120 MW can be served even if one line is out of service.*

Now imagine instead that the load at A would reach a higher level of 160 MW within the planning horizon. At that level of demand, if there was an outage of Line 2, the power flow to A from the rest of the system would overload Line 1. Because Lines 1 and 2 are identical, the same situation would occur if Line 1 was out of service instead of Line 2. Figure IV-3 depicts the situation where Line 2 is out of service, the generator at A is dispatched to its capacity of 50 MW, and the flow on Line 2 is an overload of 110 MW—exceeding its thermal limit of 100 MW.

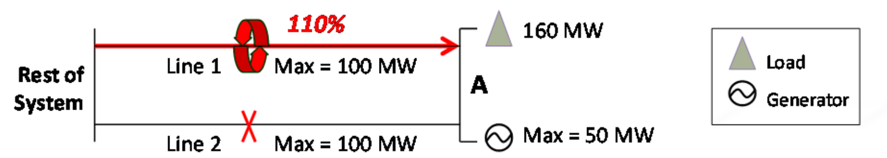

Figure IV- 3. *If the peak load at A grows to 160 MW, an outage of Line 2 would overload Line 1 and vice versa.*

SOLUTIONS

Based on the modeled network configuration and load conditions in this example, there is no dispatch solution of *existing* resources that can prevent an overload if one of the two lines is out of service. There are, however, three distinct ways that the transmission security violation in Figure IV-3 can be resolved. These are:

- Increase the capacity of <u>both</u> Lines 1 and 2, by 10 MW each; or
- Increase the generation capacity at Location A, by 10 MW; or
- Decrease the load at Location A, by 10 MW.

The first of these solutions is a traditional transmission upgrade project, potentially by re-building or re-conducting the two lines. The second and third are examples of MRAs, assuming here the additional 10 MW of generation or load-reducing modifications are procured in a competitive capacity market.

MRA IMPLICATIONS

There are three important points to note about these alternative solutions.

► **Capacity.** In this example, the quantity of additional capacity required for the transmission solution is greater than under the MRA solutions. Specifically, the transmission solution entails a total capacity addition of 20 MW, because each line must be upgraded by 10 MW for the system to be "secure" to a line-outage contingency. In contrast, an MRA that increases generation or reduces load at Location A requires a capacity addition of half as much, or 10 MW.

Note that the extent of any asymmetric capacity requirements under a transmission versus a MRA solution will depend upon the particular network configuration under study. There is no general guarantee that the MRA will entail a smaller generation or load-reduction change than the transmission upgrade. Nevertheless, in some circumstances, these capacity differences will contribute to the efficiency of MRA solutions.

► **Availability.**   In this example, each of the MRA solutions assumes that the MRA is available to increase (or decrease) power at Location A whenever one of the lines is out of service.   In practice, generation and demand-response resources typically do not have the same level of availability as a transmission line.

In the example, the availability requirement for the MRA is more than simply the peak load event of 160 MW at location A.   Any hour in which load exceeds generation at location A by 100 MW or more will require the MRA to be available, in order to prevent an overload of one line if the other is unexpectedly out of service.

► **Location.** The final point to note is the locational requirement for an MRA to be a viable substitute for the transmission upgrade. It won't do for the additional 10 MW of generation or load-reduction to be located elsewhere in the rest of the system; it must be located at A. This observation is key: It implies that if New England proceeds to procure MRAs to resolve this type of transmission security problem, the existing forward capacity market will need to be modified to procure and compensate MRAs that are proposed in the 'right' locations to resolve the problem.

We address the required changes to the FCM that would be necessary to handle these locational requirements in greater detail in Section V.

TERMINOLOGY

Before proceeding, a brief note on standards and terminology is useful. The process of evaluating how power would flow taking each power system element out of service (one-by-one) is known as an *N-1 contingency analysis.* (Here N represents the number of power system elements examined, with only N-1 of them in-service in each scenario). In the situation depicted in Figure IV-3, the system is *not secure* to an N-1 contingency—meaning that, under the modeled load conditions, a single line out of service would overload an essential component of the transmission system network.

In evaluating transmission security requirements, the planning process uses both N-1 and so-called N-1-1 contingency standards.[18] Ensuring the power system is secure to these contingency standards is a NERC and NPCC planning requirement, and standard practice in the ISO's transmission planning process.

[18] In an N-1-1 analysis, the power flow is evaluated first taking each element of the power system out of service; then the system is redispatched or reconfigured to eliminate any transmission limit violations, if possible; if so, the system is further evaluated to determine if any violation would occur should an additional, second power system element go out of service. If a violation would occur, the system is *not secure* to an N-1-1 contingency.

VOLTAGE REQUIREMENTS

The second type of transmission security constraints are voltage limits. Every transformer, line, and component of the power supply system has a nominal voltage rating. As the load on a transmission line increases, however, the voltage at the receiving end decreases. The need to maintain this voltage within specified limits constrains the transmission system's ability to meet load in one location with generation from a distant location.

In more precise terms, the relationship between voltage and power at (the receiving end of) an AC transmission element is illustrated in Figure IV-4. The vertical axis indicates voltage, and the horizontal axis indicates (real) power, at the receiving end of a transmission line. The curve in the figure, known as the *P-V profile*, determines the range of line loadings that keep the receiving-end voltage above its minimum limit.[19]

As with thermal limits, the planning process considers contingency scenarios. For example, if either a generator or another transmission line serving the same load center is out of service, the P-V profile typically shifts inward and down. Because contingencies can happen abruptly, the maximum line loading is generally determined by a post-contingency scenario, as illustrated in Figure IV-4.[20]

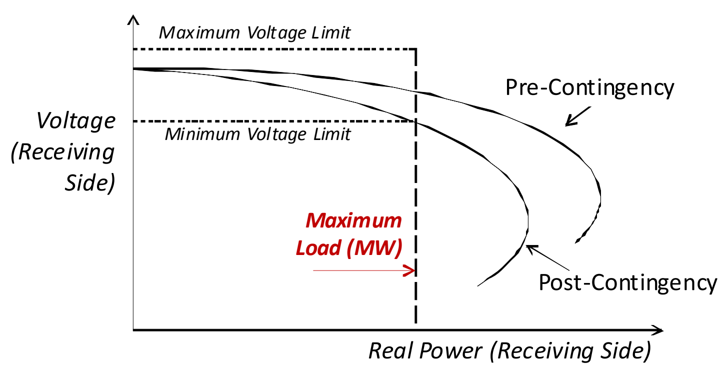

Figure IV- 4. *Line or interface loadings are limited by the admissible voltage limits of the equipment, according to a post contingency power-voltage (P-V) profile.*

[19] In practice, the ISO often models P-V profiles at the interface level rather than individual lines, but the concept is the same.

[20] Note there is also a theoretical maximum power transfer at the point where the P-V profile turns vertical. Operators must maintain load at a certain safety margin below this, instead of allowing the power flow to approach this point; near it, voltage may become unstable if system conditions are perturbed.

PLANNING PROCESS

From a system planning perspective, the objective is to ensure that load can be served while maintaining the required voltage under all modeled conditions. If load is anticipated to grow, or a generator proposes to retire, there may be no dispatch solution that maintains the voltage within admissible limits in a post-contingency scenario. In that event, the planning process will identify a need for additional infrastructure to prevent such voltage limit violations.

What type of 'infrastructure' is required? Here things are more complex than with thermal limits. Components of an alternating current power system supply and consume two types of power, one termed *real power* and the other *reactive power.* Real power does useful work (such as running motors, lights, and so on); reactive power is necessary to support voltage, and its supply is the primary concern to avoid violating voltage limits. Generally, equipment must be employed that can supply reactive power at (or near) the load center where a violation arises.

EXAMPLE

In the ISO's current regional planning process, it has identified potential future violations of voltage limits on transmission elements in parts of western Massachusetts.[21] The ISO has determined that with modest, expected load growth, there may be no commitment of existing resources that can prevent violation of voltage limits in the area under certain line-out conditions identified in the ISO's contingency analysis.

As a result of that analysis, the regional planning process has recommended a package of transmission facility upgrades in the Pittsfield-Greenfield area. The upgrades involve new equipment at several substations in the area and rebuilding several short lines between key facilities, at a projected total project cost of $93-$208 million.[22]

SOLUTIONS

There are a number of transmission system investments that can solve a potential voltage limit violation identified in the planning process. These include:

- Capacitor banks;
- Static synchronous compensators (STATCOM) and static VAR condensers (SVC);
- Upgrade existing or build new transmission lines (sometimes).[23]

All of these are able to supply reactive power. When installed in the right locations, they improve the voltage profile, thereby increasing the real power that can be transferred across the line to serve the load.

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[21] *Pittsfield-Greenfield Area Transmission Needs Assessment Final Report* (June 29, 2010), at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/reports/2010/pitts-green_assess.pdf [CEII].

[22] *Draft Pittsfield-Greenfield Area Transmission Solution Study Report* (February 27, 2012), at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/reports/2012/pittsfield-greenfield.pdf [CEII].

[23] At low loading, transmission lines supply reactive power; at high loading, they absorb it. The load level at which it switches is line specific.

Transmission investments are by no means the only potential solution, however. Other resources are capable of supplying or modifying the reactive power level at the load center, including:

- Generators, which supply reactive power;
- Reducing load of motors and other devices, which consume reactive power.

Generators are widely used to supply reactive power today in the New England system, and the ISO pays for this service (under Schedule 2 of the OATT). However, the ISO presently does not procure capacity resources for the purpose of supplying reactive power.

MRA IMPLICATIONS

There are three important points to note about these Market Resource Alternative solutions.

► **Capacity resource qualifications.** Not all existing FCM resource types are capable of supplying/absorbing reactive power (or reducing consumption of reactive power). This means that, when looking to MRAs, not all capacity resources will have the technical capabilities to solve reliability problems involving low- or high-voltage limit violations.

Demand-side resources, in particular, may or may not be suitable for this application depending on the actual means by which the resource modifies net load. Two examples illustrate possible differences:

- If the demand-side resource is a 'behind-the-meter' generator, it may be capable of supplying reactive power. If this generator is dispatchable at the times and levels needed to provide voltage support to the area, this may be a viable MRA solution.[24]

- In contrast, certain energy efficiency programs may not reduce consumption of reactive power—or could even increase it. For example, an energy-efficiency program that reduces load by swapping incandescent lights for florescent lights could actually *worsen* low-voltage conditions (because florescent lights consume reactive power).

The point to observe is that the ability of a particular capacity resource to resolve future potential voltage violations depends on specific physical characteristics of the capacity resource.

That has two implications for MRAs. First, in addition to evaluating feasible transmission project solutions, the ISO would need to specify the reactive power capabilities required of a capacity resource that seeks to be considered as an MRA to resolve a voltage problem. Second, a capacity resource that seeks to be considered will have to be screened against these requirements to ensure it can inject (or to reduce consumption of) reactive power to help reduce voltage limit violations.

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[24] At present, the ISO cannot issue voltage dispatch instructions to 'behind the meter generation' due to informational limitations (behind-the-meter MVAR is not observed).

► **Cost thresholds.** In general, mechanical capacitor banks and their modern electronic equivalents (STATCOM and SVC) are cheap relative to the cost of a new generating facility. Common sense suggests it may not make sense to model a highly local constraint in the FCM, qualify resources as MRAs to solve it, and evaluate if capacity resources can be procured in the FCA to solve it, when a transmission project could readily fix the problem with a low-cost substation upgrade.

This suggests that a *de minimus* cost threshold should be applied in the planning process before the ISO engages the apparatus of the FCM to identify and qualify MRA solutions to solve voltage support problems. The ISO notes that the appropriate cost level to apply as a *de minimus* threshold would require additional analysis and stakeholder discussion.

► **Location.** Low- and high-voltage criteria violations can be geographically widespread, or they can be local phenomena—sometimes manifest at a specific sub-station. For an MRA to be a viable substitute for a transmission upgrade, in some circumstances the area (set of network nodes) at which the MRA would need to be situated could be small. This implies that, if the region proceeds to procure MRAs to resolve this type of transmission security problem, the forward capacity market may need to incorporate potentially narrow locational constraints.

STABILITY LIMITS AND IMPLICATIONS

The third type of transmission security constraints are *stability limits*. In the high-voltage transmission system, all generators are synchronized: they rotate at a constant speed, producing current with the exact same frequency everywhere. After any portion of this system experiences a disturbance (say, a generator trips off line), the entire system is designed to regain a state of operating equilibrium at close to the initial frequency. The ability of all (remaining) generators on the system to remain synchronized after a contingency is known as *power system stability*.

Maintaining stability places limits on the amount of power that can be transmitted across various interfaces within New England and between adjacent control areas. The details are complex, but the implications for planning can be illustrated by example.

EXAMPLE

In the recent Maine Power Reliability Program transfer capability studies, the ISO identified certain conditions under which a transmission fault (to ground) could cause generators in one area of the system to become asynchronous.[25] When a high-voltage transmission element experiences a failure mode that connects it to ground, the load on the system is instantly reduced. If the load reduction is large, nearby generators will suddenly start to rotate faster. Generators that are a long way away from the fault—in

[25] See *Maine Power Reliability Program Transfer Capability Update* (March 12, 2012), at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2012/mar152012/mprp_transfer_limits.pdf [CEII].

this case, in Maine—continue to rotate closer to their pre-disturbance speed *if* they were heavily loaded at the time. The difference in rotational velocity of the near and far generators causes the system to become unstable and generators to lose synchronism. If not mitigated rapidly, the transmission system would separate Maine from the rest of New England to protect the transmission network's components from permanent damage. The time lapse from initial disturbance to instability is brief, typically less than a few seconds.

Although such events are remote, this possibility limits power flows on transmission lines between Maine and the rest of the system even under normal operating conditions. Limiting power flows ensures generators would respond at sufficiently similar rates to a disturbance, preventing an asynchronous response to the ground fault. The MW limit on a transmission interface that ensures all generators remain synchronized following a disturbance is called the interface *stability limit.*

IMPLICATIONS

The ISO's planning process examines whether changes in system conditions, such as load growth or generation retirements, may result in violations of stability limits under a wide variety of contingency scenarios. In general, if there is no dispatch solution that can prevent a stability limit violation under a modeled condition, the planning process will identify a need for an infrastructure solution to prevent stability limit violations.

The traditional transmission solutions to potential stability limit violations are upgrades to transmission system protection equipment. These include secondary (backup) protection systems, reduced breaker clearing time, and other substation-level upgrades.

Except in unusual circumstances, the ISO does not anticipate that capacity resources are likely to be viable technological substitutes for upgrading transmission protection equipment to maintain transmission system stability limits.

V. Solution Elements

Sections II through IV of this report describe the problems, causes, and constraints that must be addressed to improve the alignment of planning and markets. In this section, we elaborate on the main solution elements.

Stated in succinct terms, MRA solutions require a new, ISO-driven, externally transparent process to assess the technical requirements of an MRA for an identified transmission security constraint, including admissible locations. It then requires procurement of the MRA at the required location(s) within the FCM, with appropriate compensation that provides market incentives for new resources to locate where they are effective.

The existing planning and market processes can be enhanced to perform these functions. There are three key elements:

- *Aligning Timing:* Better aligning the timing of markets and planning functions;
- *MRA Assessments:* A new process to assess the MRA requirements necessary to resolve specific locational reliability needs;
- *Changes to the FCA:* Changes to the capacity auction design that enable competitive procurement of capacity MRAs through additional, and potentially more complex, locational constraints than in the FCA today.

These elements would enable both locational and system-level reliability requirements to be incorporated into the resource adequacy markets, reducing the need for cost-of-service transmission projects. The balance of this section covers each element in greater detail.

A. Aligning Timing

The timing and sequencing of existing planning and markets' functions is not well aligned. This creates *information flow* problems, preventing essential information produced in one venue from being incorporated into the other in a timely manner.

The solution to this problem is to modify the planning process and its sequencing to accommodate essential information flows between them. The necessary timing adjustments appear both feasible and modest in scope.

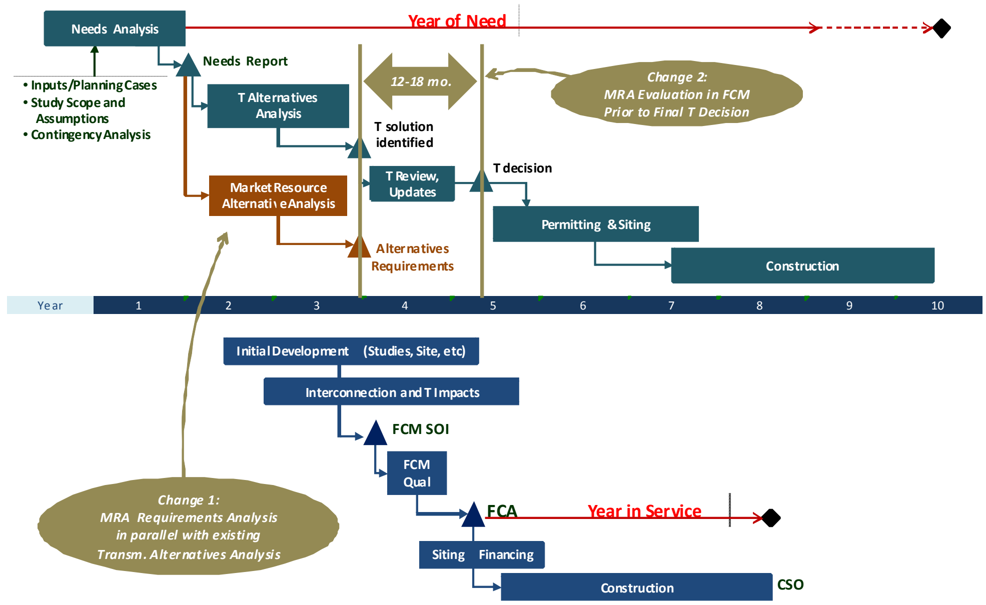

Figure V- 1. Two changes to the regional transmission planning process timing.

Before addressing these adjustments in detail, an expositional note: In Section II.B, we listed timing problems as the third (of three) root causes of planning and markets' misalignment. It is useful to address this issue first here, before addressing the other two, because understanding the resolution of information flows between market and planning decisions facilitates explanation of the remaining solution elements.

Planning Timeline

As discussed in Section II.B, the current transmission planning process would not provide adequate time for markets to develop and offer MRAs in response to an identified locational reliability need. This timing problem would result in transmission solutions moving well into the permitting and siting stage, where they may incur substantial development costs, before the resource adequacy market is able to produce an alternative capacity resource solution.

Timing adjustments to resolve this problem can be visualized in a timeline. Figure V-1 shows, at a conceptual level, a revised planning and markets sequence. There are two key changes from today's timeline discussed earlier (*c.f.* Figure II-1, p. 16).

The first is the addition of a new planning process to analyze the feasibility and technical requirements of MRAs to resolve (in whole or in part) transmission security constraints identified in the planning process. This process is shown in Figure V-1 as the red box labeled Market Resource Alternatives Analysis. It occurs at the same time as, and in parallel with, the existing regional planning process evaluation of transmission solution alternatives. Both processes are shown in Figure V-1 as taking one to two years, and being complete at about the same time (shown here at the end of year 3).

The second change from today is an additional 12-18 months in the transmission planning process, in order to accommodate efforts to procure capacity MRAs prior to making a final decision on a transmission solution. In Figure V-1, this occurs between year 3 and year 5.

PURPOSES

The purposes of these two timing modifications are to provide the resource adequacy market with time to (i) analyze, develop, and offer MRAs that meet the technical requirements, which are determined in parallel with transmission solution studies; and (ii) procure MRAs, if possible, through the FCA. The former cannot commence until after the MRA requirements are completed, shown in Figure V-1 at the end of year 3; it also should occur in advance of the FCM show-of-interest ('SOI') and qualification process windows.   Condition (ii) requires that the FCA occur prior to the point when significant transmission development costs would be incurred. This means that a final decision on the transmission solution be deferred until after the FCA in which the MRAs are solicited (shown here in early year 5).

The principal consequence of the timing changes is that they require the planning process to address system planning needs earlier than otherwise. This can be seen at the top right of Figure V-1, where the additional 12-18 months during the planning process pushes out the 'year of need' horizon from early in year 9 into year 10 for a transmission project with a 5-year siting and construction phase.

We should emphasize that the exact timing of the planning process can vary widely with the nature of the reliability assessment and transmission solution. A modest substation upgrade takes less time than a major transmission line.

Moreover, the current planning process is inherently iterative in nature. Reliability needs assessments are revised, which alters transmission solutions, and may alter MRA requirements. While Figure V-1 simplifies this iterative nature of the process, the central implication is that such iterations should proceed, as they do today, until the region must make a final decision on whether to seek capacity MRAs or to proceed with a transmission solution.

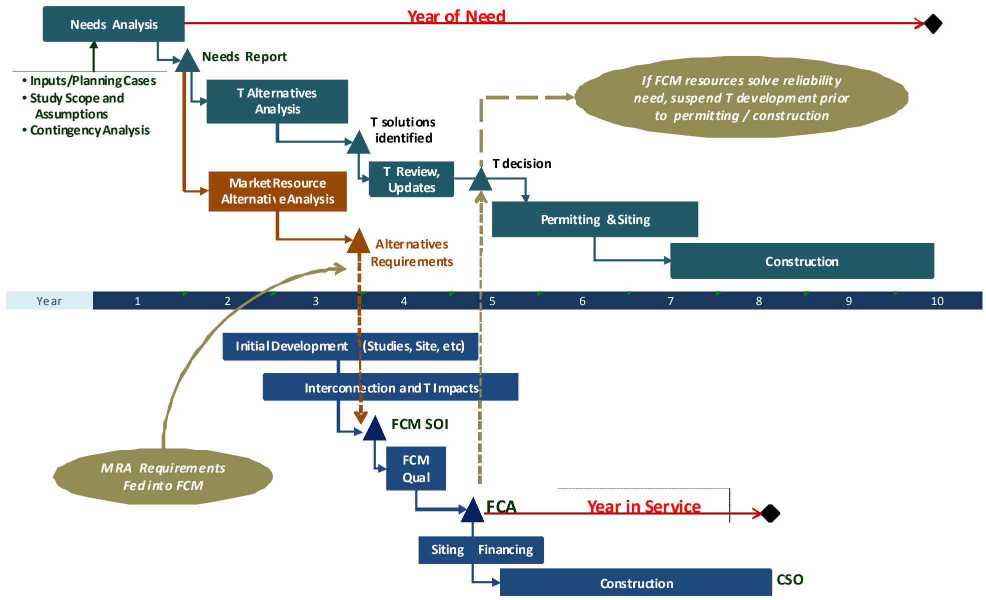

Figure V- 2. Key information flows to align planning and markets.

INFORMATION FLOWS

A useful way to view sequencing of planning and market activities is through the alignment of information flows. These are shown visually in Figure V-2.

Here, there are two information flows that must be properly sequenced between the planning and market processes. The first is the flow of information regarding locational and technical requirements of MRAs, from the planning process into the FCM. This is indicated in Figure V-2 by the vertical dashed line at the point where the MRA Alternatives analysis is completed, shown here in mid-year 3. We expand on this alternatives analysis process in Section V.B, next.

The second flow of information is the result of the FCA, which must feed back into the transmission planning process. This is indicated by the vertical dashed line after the FCA is held, shown during planning year 5 in Figure V-2. The relevance of this information is that if the FCM is able to procure sufficient MRAs to substitute for a transmission solution, then development of the transmission solution would be suspended at that point. This should take place prior to the point when significant development expenses for permitting and siting would be incurred by the transmission project.

Retirement and De-List Evaluation Timing

Reliability assessments of generation retirement (de-list bids) are presently reactive. This can be disruptive to the market, and affect the market prices paid to other resources. If a resource is held for reliability at a cost above the market-clearing price, the FCA failed to signal the value of capacity in that location. The ISO's actions, in holding a resource for reliability, indicate that capacity in that location is essential to system reliability—and therefore may have greater value than capacity elsewhere in the system.

If the ISO continues to manage the reliability assessments of generation retirements in a reactive way, MRAs can be considered as an alternative to a 'backstop' transmission project. However, the timing remains less than ideal under that approach. A retirement request that is rejected for reliability reasons would trigger, in parallel, both an assessment of preferred transmission solutions and an assessment of MRA requirements to solve the locational reliability problem. Once both are complete, the subsequent FCA may reveal if new capacity MRAs can solve the locational reliability problem. However, the elapsed time for this evaluation process could take up to 2-3 years, unless advance work by the ISO and affected parties is able to accelerate this process in specific cases.

Proactive Approach

A better approach would be to analyze reliability issues associated with generation retirements proactively. Ideally, two to three years in advance of potential generation retirement (de-list bid) requests, the ISO would perform forward-looking reliability needs assessments. The timing of transmission solution and MRA requirements analyses then proceeds along the same timeframe indicated in Figure V-2. The location, megawatts, and other attributes of an MRA needed to address the transmission security concerns associated with the generator's potential retirement could then be reflected in the FCA in a timely way.

This proactive approach has the important benefit that if a new capacity resource is offered in the FCA that meets the MRA requirement, the auction mechanism may enable the retiring unit to exit without reliability repercussions. In effect, modeling the locational reliability requirement as a procurement constraint in the FCA signals to the marketplace—in dollar terms—a locational reliability need in order to induce entry in more effective locations.

As a practical matter, achieving the benefits of this proactive approach given the potential generation retirements discussed in Section II requires taking action now. For generation that may retire toward the end of this decade, evaluation of any affected transmission security constraints needs to be performed so that the relevant locational reliability constraints can be incorporated into the FCA for appropriate capacity commitment periods. Accordingly, as part of this Strategic Planning Initiative, the ISO is presently undertaking a generation retirement assessment of approximately 30 facilities to evaluate whether their exit would adversely affect locational or system-level reliability requirements.[26]

B. Alternatives Analysis

The second key solution element is an assessment process for MRA technical requirements. The central purpose of this assessment process is to determine the locational and technical requirements that would be sufficient for MRAs to resolve a (existing or future) transmission security problem identified in the planning process.

Part IV of this report explained the underlying technical basis for why the scope and feasibility of MRAs will vary with locations and situation-specific circumstances. In this section, we elaborate on several implementation issues and provide illustrative examples. These address the scope of the MRA assessment process, complexity of admissible location sets for MRAs, cost thresholds to consider MRAs, and technical requirements of MRAs. Taken together, these considerations indicate that the planning process will require a set of guidelines for evaluating the requirements of MRAs that embody several trade-offs between complexity, transparency, and potential benefit.

MRA Technical Assessments

Assessing MRA requirements adds a new component to the planning process. We envision this operating in parallel with, and in similar fashion to, the existing transmission alternatives analysis process used in the regional planning process (see Figure V-2). Accordingly, it would be an open, ISO-driven, technical forum for analysis, discussion, and presentation of planning studies examining the feasibility of MRAs to resolve specific, identified reliability needs.

The major inputs into an MRA requirements assessment are the same reliability needs assessment results, study scenarios, and assumptions that are already used in the planning process to identify future violations of transmission security constraints. The major outputs of this process are the locations (i.e., sets of admissible nodes for an MRA), quantities (i.e., megawatts), and any other technical requirements (e.g., reactive power capability) of capacity resources that suffice to resolve an identified specific reliability need.

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[26] *See Strategic Transmission Analysis Update* (December 13, 2011), at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2011/dec142011/strat_trans_analysis.pdf and *Strategic Transmission Analysis Update* (March 15, 2011), at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/mar142012/strat_trans_analysis.pdf.

As indicated in Section V.A., the ISO believes it is important to undertake these MRA technical assessments proactively. That would facilitate the entry of new capacity resources that reduce the need for backstop transmission upgrades in response to generation retirement (de-list bid) requests.

PRACTICALITIES

At least initially, the ISO expects that the planning process will need to focus selectively on identifying situations that are candidates for MRAs. There are several reasons for this. First, as we convey below, identifying MRA technical requirements is apt to be a time-consuming process. This suggests the region's efforts would be best spent, at least initially, on cases where MRAs are likely to have high potential benefit relative to transmission solutions. In some cases, a 'reality check' early in the MRA analysis process may indicate that MRAs are, or are not, likely to be technically capable of helping resolve a transmission security constraint.

Second, for some transmission security constraints, the set of MRA locations and quantities (megawatts of capacity required) can be complicated to specify. We explain how and why in examples below. The implication will be that it may be impractical to specify and administer such complex locational constraints in the FCA. This may necessitate a coarser modeling approach in the resource adequacy markets, and simplified MRA requirements. Simplifying the transmission system's topology is not 'free'; using simplified representations of transmission constraints in the FCA can come at a cost of making MRA solutions less attractive.

We explain and illustrate these points below, using several examples. The examples draw out a number of important issues and challenges the region will have to address to go from an idealized model of how MRAs would work to a feasible MRA technical assessment process that the ISO can implement.

LOCATIONS AND IMPLICATIONS

It is useful to illustrate how several different MRA locational requirements can emerge in an MRA assessment, using even a 'simple' transmission network. Here we provide an example that indicates how, under ideal circumstances, MRAs with different location-and-quantity (MW) attributes can resolve the same transmission security constraint as would a transmission upgrade. In doing so, the example highlights several key trade-offs that will have to be made when assessing MRA locational requirements.

In addition, this example reveals inherent inefficiencies of the existing resource adequacy market design that could be improved with more granular locational price signals. In theory, these price signals should provide incentives for new capacity to locate in the most effective sites—which depend a great deal on the structure of the transmission network.

Although the example below is simplified for transparency, it is not purely hypothetical. Rather, it is illustrative of the type of analyses the ISO has conducted for MRAs in the

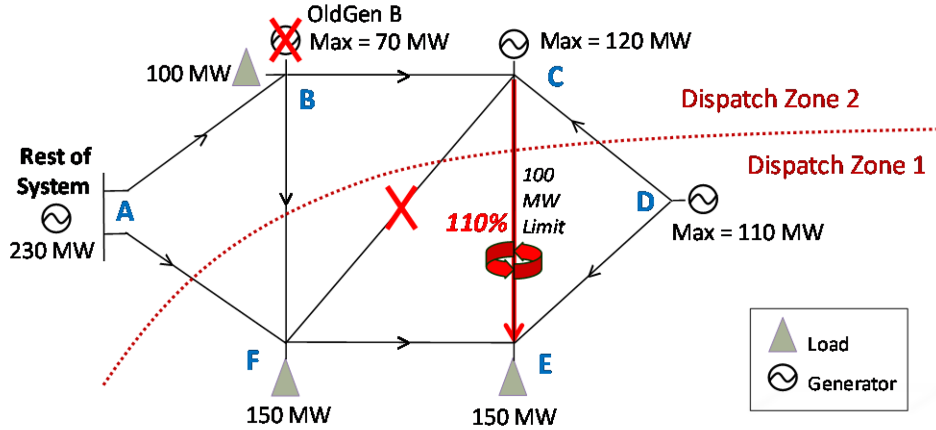

Figure V-3. *The network is not N-1 secure if OldGen B retires, but new capacity at B or at other locations can resolve the security problem.*

context of the Vermont/New Hampshire planning studies[27], and that are presently underway as part of the Greater Hartford and Central Connecticut planning studies.[28]

EXAMPLE

Consider the six-node network in Figure V-3. Generation and load are located as shown; we treat node A as a robust (secure) connection to the rest of the system that can import up to 230 MW. For simplicity, assume each line has a high flow limit, except for line C-E that has a maximum flow limit of 100 MW. The total load in this sub-system is 400 MW.

In order to focus on key issues for MRAs, we discuss next several insights illustrated by this six-node system. These properties follow from a standard power flow analysis, the mathematics of which we omit here.[29]

The total load in this sub-system can be satisfied if all lines and generators are in service, while achieving N-1 security. Now imagine that OldGen at location B proposes to retire. If OldGen at B retires, the system will not be N-1 secure: Without any generation at B,

[27] *Nontransmission Alternatives Analysis – Results of the NH/VT Pilot Study* (May 24, 2011), at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2011/may262011/nta_analysis.pdf [CEII].

[28] *Market Resource Alternatives – The Next Study* (December 12, 2011), at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2011/dec142011/mra.pdf.

[29] Verification of the MW results that follow requires a routine but lengthy set of linear power flow calculations, and supplemental information on assumed line impedances. For present purposes, we omit contingencies elsewhere in the rest of system, and ignore N-1-1 analysis.

if line C-F is out of service, then the power flow on line C-E would be 110MW, which exceeds 100 MW (thermal) flow limit. See Figure V-3.

Assuming these are modeled load conditions for this area analyzed in the planning process, planners might identify the following transmission and MRA solutions to the transmission security violation (thermal overload of line C-E) without OldGen B.

► **Transmission solution.** Clearly, one solution is to increase the capacity of the transmission line between C and E, from 100 MW to 110MW. Under current practice, if OldGen B elects to retire, the planning process would trigger an upgrade of the transmission system to ensure it can continue to deliver the remaining generation to load.

► **MRA 1.** When transmission security violations are prompted by generation retirements, another solution is to locate replacement generation at the same site. In this example, the addition (or repowering) of 43 MW of capacity at B would resolve the transmission security problem, and restore N-1 security to the system.

Note the difference in MW required for the generation and transmission solutions here. Locating new generation at B requires *four times* the MW that would be added to line C-E's transfer capacity under a transmission solution. Note, however, that if the line from C-E is very long, and the cost of a transmission upgrade is high, then adding a greater amount of capacity at B may be a more efficient solution.

► **MRA 2**. For some networks and load patterns, locating generation at a different site than that of the retiring facility may be a more effective solution to the transmission security problem. In this example, another MRA solution is to locate new capacity at E instead of B. If so, only 13 MW of new capacity would be required, instead of 43 MW at B.

Note this means we can restore N-1 security by adding only one-third as much capacity at E than the amount that would be needed at B. Put another way, the value of a MW of (otherwise identical) capacity at E is three times greater than a MW of capacity at B, as far as solving this transmission security violation is concerned. The reason is that capacity at E is more effective at providing constraint relief on line C-E than capacity anywhere else in this system. Such locational differences in the value of capacity hold generally; they are a result of the system's load and generation pattern (location E is a major load center in this example), the network topology (power transfer distribution factors between network locations), and the set of contingencies studied.

► **MRA 3.** Now consider a demand-side solution. Here we assume demand-response (DR) capacity resources are callable by 'zones', and may elect to locate at any load node within its specified zone. In this example, if a demand-response capacity resource solution is acquired in DR Dispatch Zone 1, it would require 24 MW of DR capacity resources.[30]

The reason more capacity is required under MRA 3 than under MRA 2 is the specificity of the location. If the load-modifying assets' locations are not node-specific, but can be anywhere within Dispatch Zone 1, then the capacity required must be high enough to ensure the transmission security constraint can be resolved regardless of whether the load reduction occurs at E, at F, or any combination thereof. If all load modifications within Dispatch Zone 1 actually took place at location F, which is less effective at solving the C-E overload than capacity at E, then 24 MW would be needed.

IMPLICATIONS

These three MRA solutions illustrate several important points about MRA technical assessments that apply generally.

► **Reason for locational differences in the value of capacity.** The most effective places to locate capacity depend, in precise ways, on the structure of the transmission network. As noted above, capacity located at E is three times more valuable (per MW) than the capacity of the OldGen at B (with respect to maintaining N-1 security). These locational differences in the value of capacity, and their sensitivity to the topology of the transmission system, are ignored in the current forward capacity market. Ignoring these differences is a source of economic inefficiency with an insufficiently 'granular' locational capacity market.

► **Trade-off between locational specificity and capacity required.** There is a trade-off between the amount of capacity required of MRAs and the specificity of the locational requirement. In the example, only 13 MW is needed if it is a location E; but nearly double that, or 24 MW, is needed if the requirement allows the capacity to locate anywhere in an area consisting of E and F. If the locational requirement is broadened further to an area consisting of B, E, and F, then a minimum of 43 MW of new capacity would be required. If it is broadened to a still larger area consisting of B, D, E or F, additional calculations indicate that at least 48 MW of new capacity would needed.

The point to note is that, in general, MRAs requiring less capacity are possible when acquired in the 'right' locations. In general, if the MRA requirements specify broad areas or zones, then more capacity must be procured to resolve the same transmission security constraint.

► **Incremental versus total area capacity.** Whatever 'size' of the area is selected, there is a choice to be made regarding how the MRA megawatt requirement is formulated in the FCA. In principle, locational constraints could be formulated in terms of *incremental* capacity, or in terms of *total capacity,* needed in an area to substitute for a transmission upgrade. The former is potentially more complex to formulate and administer than the latter.

[30] The demand-side resources in Zone 1 are assumed to locate at E or F in this example, as there is no load at D.

For example, consider the locational capacity requirement for an area consisting of four nodes, {B, D, E, F}, to resolve the C-E thermal security violation once OldGen B retires. This area has a capacity of 110 MW (located at D); see Figure V-3. As noted previously, the locational capacity requirement to avoid the transmission upgrade could be specified as 48 MW of *additional* capacity anywhere in that area. This additional capacity amount is contingent on B's retirement, and the existing 110 MW generator at D remaining in service. If B seeks to dynamically de-list, then the actual MRA requirement would depend on whether B clears or not. It would also depend whether the generator at D clears in the FCA. The real network may have many such contingencies, which can become difficult or impractical to formulate in the action clearing procedures.

Alternatively, and generally more simply, the locational capacity requirement to avoid the transmission upgrade could be specified as a *total* of at least 158 MW located (distributed) anywhere in the area consisting of {B, D, E, F}. Then the megawatt requirement is not contingent on what generators at B or D choose to do. If 158 MW of capacity clear in the area, regardless of what combination of new and existing resources it may be, that level of capacity would resolve the transmission security constraint and avoid the need for the transmission upgrade.

► **Complexity.** Different feasible MRA solutions can create complex constraints. Ideally, to find the most effective solution one would evaluate all feasible solutions. Even in this simple (six-node) example, evaluating each feasible MRA solution within the FCM would require formulating a complex locational constraint within the clearing engine of the FCA. Specifically, the constraint would need to specify procurement of *either* 13 MW of qualified capacity at E, *or* 24 MW of qualified capacity in an area consisting of E and F, *or* 43 MW of qualified capacity in an area consisting of B, E, and F, *or* 158 MW of qualified capacity in an area consisting of B, D, E, and F.

Formulating locational procurement requirements with that level of 'nested' alternatives can become impractical rather quickly. This is not a hypothetical or theoretical concern; for New England's transmission system, examination of locational requirements in studies to date indicate this type of complexity may arise often. We elaborate on exactly this point with a real example, below.

The central implication is that using 'simple' representations of MRA admissible sets (locations and quantities) will undoubtedly be necessary for MRAs to be incorporated within the forward capacity market. There are a number of ways to construct even 'simple' representations, however, as we discuss next.

ISSUES AND CHALLENGES

The foregoing examples present a simplified and, in some respects, ideal depiction of how MRA analysis can identify locational and quantity (MW) requirements for capacity resources that would resolve a transmission security problem identified in the planning process. In practical application, there are a number of challenges and issues. We highlight these issues here, and some observations on their significance, as they will become important for the ISO to move from a conceptual view of MRAs to a feasible implementation.

SOLUTION COMPLEXITY

The first problem is the potential complexity of the location-quantity requirement sets for feasible MRAs. An example from the Vermont/New Hampshire Pilot Study of MRAs is an informative case in point.

In the Southern New Hampshire component of the Vermont/New Hampshire planning studies, the identified reliability needs are resolution of thermal and voltage violations under projected load conditions over the planning horizon. In addition to analyzing transmission solution alternatives, the ISO conducted a simplified (thermal-only) MRA analysis of what would be required of MRA capacity resources to address the identified reliability needs.[31] The analysis revealed that, to use the least amount of new capacity resources, the capacity could not simply be added anywhere within a 'zone'-type construct; rather, the set of feasible MRAs took the form of highly specific amounts in precise locations, all added simultaneously. Specifically, additions take the form of 55 MW at one network node, and 160 MW at a second node, 70 MW at a third, 90 MW at a fourth, 15 MW at a fifth, and so on… In the end, this MRA solution requires different MW levels of new capacity at 13 different, specific nodal locations in southern New Hampshire. In effect, for all thermal overloads to be resolved without transmission upgrades, generation has to be carefully balanced at every location.

IMPLICATIONS

The points to observe here are two. First, incorporating within the FCA a locational procurement constraint that requires specific generation amounts to be acquired in 13 different places (at the bus level), in 13 different MW levels, simultaneously, is apt to be administratively impractical. Instead, some aggregation of these locations into a broader area would be needed. At least initially, it may be preferable to start with one (or perhaps two) locational constraint(s) in the resource adequacy market that will satisfy a transmission security problem identified in the planning process. This would simplify the FCA clearing process and lend greater transparency to the results.

Second, aggregation to a broader area for an MRA will necessarily entail a greater total new capacity requirement to meet the locational constraint and substitute for the transmission alternative. This is the same observation highlighted in the six-node example previously; there is a trade-off between the size of the area (number of admissible nodes) in which an MRA may locate and the total capacity required to ensure the transmission security requirement is met.

These trade-offs may be significant. It is reasonable to expect that broader areas within which an MRA may locate are likely to attract greater entry and competition in FCA.

[31] *Nontransmission Alternatives Analysis – Results of the NH/VT Pilot Study* (May 24, 2011), p. 43-49, at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2011/may262011/nta_analysis.pdf [CEII].

However, the cost and efficiency benefits of greater competition may be tempered, or even offset, by the need to require greater capacity overall when the MRAs are allowed to locate in broader areas. The specification of the locations-and-quantities set required of MRAs will be a challenging issue for implementation, as it is likely to be difficult to quantify in the abstract.

Moreover, if only a small amount of capacity is needed but must be procured at a narrow set of admissible locations, competitiveness may be hampered by the inflexibilities of the existing interconnection rights system. This may warrant conditional qualification of resources, to address overlapping impacts results during the MRA qualification process.

THRESHOLDS

Another "lesson learned" from the ISO's work to date is that in some, perhaps many, situations it will be apparent early on that MRA solutions either are, or are not, within the range of possibility as an effective solution on technical grounds.

The simplest such examples arise in cases where transmission security requirements call for modest upgrades to substations. For instance, suppose the planning process indicates a need for additional reactive power that can be achieved with installation of capacitors a specific substation, for a total cost of (say) several million dollars. Procurement of new capacity resources to meet this identified reliability need may not merit serious consideration.

As noted in Section IV.B, this observation suggests that initiating the MRA Requirements assessment process should be subject to a *de minimus* cost threshold, based on the expected costs of transmission solution(s). If a transmission solution is expected to be available at a cost less than the specified *de minimus* threshold, the planning process would proceed as it does today without seeking to procure MRAs in the FCM.

SEQUENCING

An additional complication that arises in conducting MRA analyses is sequencing. In general, the locations and quantities of capacity that are needed to solve a transmission security requirement depend on what other capacity resources exist in the system.

For example, in analyzing prospective MRA requirements to resolve a transmission security issue that may occur if a generator retires, the answer may depend—perhaps delicately—on what other generators are assumed to retire elsewhere in the system. As a result, assessing MRA requirements that address each retirement sequentially may produce different results than if the requirements are developed assuming several units retire. A key issue will be whether MRA solution requirements must be robust to potential, but not yet declared, retirements of generating units that may further aggravate the transmission security constraint.

These sequencing, or interdependency, problems may be difficult to solve efficiently unless there is sufficient lead-time information on planned retirements. The ISO is expecting that its current study of potential generator retirements and transmission security consequences will shed greater light on the significance and scope of these interdependencies (*c.f.,* Section V.A, p. 36-37).

OTHER TECHNICAL REQUIREMENTS OF MRAS

A central point of the technical discussion in Section IV.B is that some types of transmission security constraints will require specific physical capabilities of MRA capacity resources. Here we illustrate and amplify this point.

Consider again the three MRA solutions described for the six-node system in Figure V-3. These three MRA solutions assume that the capacity resources offered as MRAs would be fully available in the event of an N-1 contingency that overloads line C-E. What does 'fully available' actually mean, in practice? Here, reality may necessitate important technical requirements on MRAs to ensure they can indeed substitute for the transmission upgrade.

To extend the example, let's suppose MRA Solution 1 is implemented, in which 13 MW of new capacity enters at location C. In reality, in order for the MRA to provide the required first-contingency protection for line C-E, this new capacity resource would need to be either (i) online any time line C-E fails or (ii) able to get online and inject the required power (at least 13 MW) within the time limit of line C-E's emergency load rating. Realistically, condition (i) is not possible 100% of the time (except possibly through energy efficiency load reductions). That means, to ensure condition (ii), a generation (or demand-response) capacity resource may need to have fast-start capability within 15-30 minutes to unload the line in timely fashion (this depends on the line's ratings and post-contingency overload severity). In sum, not any capacity resource will work. To resolve a specific transmission security constraint, an MRA in some situations may need to have capabilities that go beyond those required of capacity resources generally.

Another example relates to the capacity resource's available hours per year. Suppose that the identified transmission security problem is low voltage conditions in part of the transmission system under load conditions that prevail 1000 hours per year. In such cases, an MRA would need to be available for commitment at least the corresponding number of hours annually. Moreover, the technical requirements of the resource would include reactive power capability in order to provide adequate voltage support. The technical requirements may also necessitate maximum startup time requirements, to ensure the resource can get online between when low-voltage conditions are projected to occur by the ISO and when the conditions requiring voltage support are expected to prevail (say, during peak hours of the operating day).

The central point to note here is that while determining these additional requirements is not an insurmountable problem, it will complicate the MRA technical requirements assessment process. Physical requirements for MRAs that go beyond those required of other FCM resources will need to be assessed by the ISO prior to the FCA, presumably in the FCM qualification process. Ideally, such requirements would not expressly require one technology or another, but rather would list the performance or physical capabilities that are necessary to substitute for the transmission solution and meet the local reliability requirement. Overall, in some circumstances the physical performance requirements of an MRA may be quite specific to the transmission security constraint they must resolve.

IMPLICATIONS AND PRACTICALITIES

Taken together, these considerations indicate that the MRA assessment process will require a set of guidelines that embody numerous practical trade-offs between complexity, transparency, and potential benefit.

At least initially, the ISO believes that planning engineers should have a set of conditions available to test, or 'screen', for whether a MRA is a technically viable solution to a transmission security requirement. The elements that may be reasonable to include in this screening test are:

- **Complexity**: Whether the locations-and-quantities required of MRAs to resolve the transmission security requirement are not inordinately complex, and can be distilled down to specifying one, or possibly two, quantity-and-area (set of admissible nodes) combinations for the capacity resources;
- **Thresholds**: Whether a transmission solution's projected costs exceed a *de minimus* threshold, and that the costs of capacity resources in the amounts required for an MRA falls within the realm of plausibility as an effective solution;
- **Technical feasibility**: Whether the technical requirements of an MRA (availability, response time, etc.) would be achievable by capacity resources situated in the required area, including whether there is sufficient interconnection space to accommodate capacity resources' development.

In addition, from a process standpoint, the MRA assessment process will need a set of guidelines to govern the sequence of transmission security requirements to be analyzed proactively. This is particularly important for formulating constraints in the FCM with regard to potential, but as yet undeclared, generation retirements that may precipitate transmission security problems.

Finally, the ISO expects that, like transmission planning generally, MRA technical assessments may be a time-consuming, stakeholder-intensive process. Accordingly, the ISO expects to focus, at least initially, on situations where the potential benefits of MRAs are large relative to a transmission expansion project. Such situations are likely to arise in several near-term cases prompted by generation retirements, where a new capacity resource may be well-suited to resolve a transmission security concern. Other candidate situations may arise as suggested by the New Hampshire/Vermont planning studies, where a transmission solution may require a new, long line that would be expensive but only a small amount of additional capacity would be required under an MRA solution.

C. Forward Capacity Auction Changes

The third key solution element is to procure, in a competitive manner, capacity resources that meet the technical requirements of an MRA. Today, in the forward capacity auction (FCA), capacity resource owners make, and receive if cleared, binding financial commitments to develop new resources and operate existing resources. The FCA's existing design can accommodate some locational constraints, but these constraints are broad zones. As MRAs with more complex requirements (locationally and otherwise) are sought, some enhancements to the existing FCA features will become necessary.

Several features are important to the concept of procuring capacity MRAs to transmission solutions through the FCM. These are:

- *Incorporating the required amount of capacity MRAs as a constraint in the FCA.* Resources that qualified as satisfying the MRA requirements associated with a particular reliability constraint would, if cleared, contribute to both the MRA constraint as well as the system-level resource adequacy requirement.
- *Equivalent prices for new and existing resources that contribute equally to reliability constraints.* All resources that qualify to meet a specific MRA constraint, and are cleared to meet the MRA constraint, would be paid the same price for their contribution to the reliability constraint.
- *More granular pricing of capacity than today.* In general, an auction could produce many different prices if there are many binding constraints. The price paid to resources that are cleared to meet a particular MRA capacity constraint could be higher or lower than another MRA constraint's price, and may differ from the system-level market clearing price.

These features would enable the FCA to efficiently procure capacity resources as MRAs in the amounts and locations needed and in a manner that is well-aligned with existing resource adequacy market design. The central objective of the enhanced locational pricing features are to ensure that clearing prices provide appropriate incentives for, and reflect the cost of, locating capacity resources where they help resolve locational reliability problems.

To a large degree, only minor changes to the FCA's existing design would be needed to accommodate these features when the MRA capacity constraints take a relatively simple form. By 'simple', we mean a locational constraint that is one-way (e.g. import-only or export-only, but not both) and does not intersect with any other constraint. As more complex forms of MRA reliability constraints and locational patterns emerge over time, constraints may no longer be so simple, and more significant changes to the FCA's design and format may become necessary.

In this section, we proceed in two parts. First, to fix ideas, we present a simple example of how the FCA can accommodate simple MRA capacity constraints. While this is similar to an (ideal) functioning of the existing capacity zone (LSR) structure, it will nevertheless serve to illustrate several points and provide a framework to discuss complications that arise in more general cases.

Second, we then discuss in detail a number of issues and complexities related to incorporating more detailed constraints within the FCA. In brief, these include:

- Duration of locational constraints in FCA
- Implications for existing LSR zones
- Package alternatives
- Lumpiness of transmission and generation alternatives
- Multi-directional constraints
- Problems with the DCA format

Taken together, the purpose of addressing these issues and complexities is to ensure that the FCA's clearing prices provide appropriate incentives for, and reflect the cost of, having capacity resources locate in more efficient places where they can simultaneously contribute to both locational and system-level reliability requirements.

EXAMPLE

An example of how the FCA can clear capacity MRAs to meet a locational reliability requirement ties together the preceding ideas. Here we consider how the FCA would address a single locational reliability requirement.

ASSUMPTIONS

Imagine the system consists of two areas, A and B, as illustrated in Figure V-4. Table V-1 (*next page*) shows twenty (hypothetical) capacity offers submitted in the FCA and their locations (either area A or B). The system-wide capacity requirement is 34,000 MW.

There is 1500 MW of existing capacity in area B. We assume the regional planning process has identified a future local reliability (transmission security) constraint on power imports from area A to B that cannot be satisfied, under modeled planning conditions, due to projected load growth. The preferred transmission solution is to increase the transmission capability from A to B.

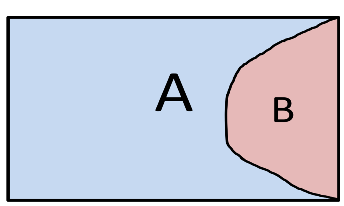

Figure V-4. *The two areas. Area B is import constrained.*

Suppose now that the MRA requirements analysis indicates the reliability requirement could be satisfied with 1000 MW of new capacity resources in area B, instead of the transmission solution. As discussed in Section V.B, this means the locational requirement could be formulated in the FCA as 1000 MW of *incremental* capacity resources in area B, or as 2500 MW of *total* capacity resources in area B. For the reasons discussed therein, we assume the FCA locational constraint is formulated using the total, rather than incremental, method. For simplicity, we assume that all capacity offers in area B (whether new or existing) would contribute to satisfying the locational reliability constraint.

WHAT CLEARS?

What clears in the auction? The simplest means to see what clears is to look at what offers will drop out as the descending clock auction proceeds. This can be done by walking up, from the bottom, the offers in Table V-1. At the start, a total of 3500 MW are offered in Area B that can contribute to that area's 2500 MW reliability constraint. As the price falls from its initial (high) starting value, the highest-priced offers will drop out. When the auction price falls (just) below $5 per kW-month, Offers #19 and #20 will have dropped out (de-listed in the auction).

Table V-1. Twenty Capacity Auction Offers

Offer #	Area	New or Existing?	Quantity (MW)	Offer Price ($ / kW-mo)	Cumulative MW Cleared in A	Cumulative MW Cleared in B
1	A	Existing	10,000	1.500	10,000	
2	A	Existing	5,000	1.550	15,000	
3	A	Existing	3,500	1.600	18,500	
4	A	Existing	4,000	1.650	22,500	
5	A	Existing	5,000	1.750	27,500	
6	A	Existing	3,000	1.800	30,500	
7	B	Existing	1,000	1.810		1,000
8	B	Existing	500	1.830		1,500
9	A	Existing	1,000	1.850	**31,500**	
10	A	Existing	500	1.900	*not cleared*	
11	A	Existing	500	1.950	*not cleared*	
12	A	Existing	500	1.975	*not cleared*	
13	A	Existing	500	2.000	*not cleared*	
14	A	Existing	500	2.100	*not cleared*	
15	A	New	500	4.300	*not cleared*	
16	A	New	500	4.500	*not cleared*	
17	B	New	500	4.600		2,000
18	B	New	500	4.800		**2,500**
19	B	New	500	5.000		*not cleared*
20	B	New	500	5.100		*not cleared*

Note: All data in this table are hypothetical for example purposes.

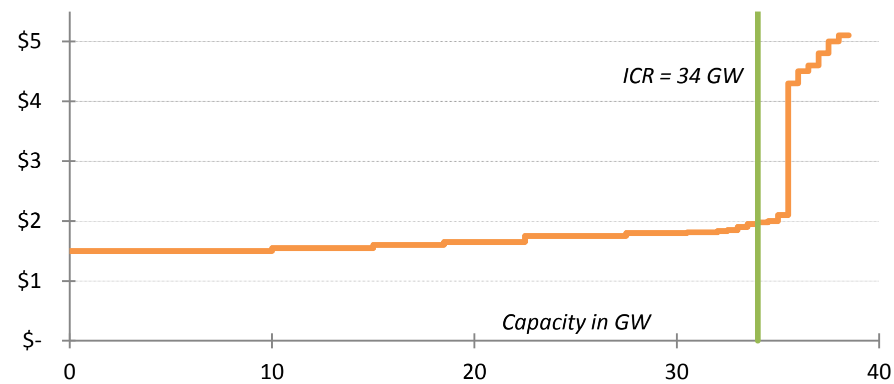

Figure V-5. ***The full supply curve for all capacity offers in Table V-1.***

At that point, there are only 2500 MW of resources left in Area B, which just satisfies the Area B locational constraint. The remaining offers in Area B must be cleared to satisfy the locational constraint. These are the existing resources (Offers #7 and #8) and two new resources in Area B (Offers #17 and #18). If the clearing price in Area B is set by the last accepted resource in Area B, then the price paid to all resources in Area B is that of Offer #18, or $4.80 per kW-month.

What happens in the rest-of-system? The auction continues. Because 2500 MW have already been cleared, the rest-of-system must clear only the ICR less 2500 MW, or 31,500 MW. This occurs when we reach Offer #9, which must be accepted to clear 31,500 MW in area A. Assuming the last accepted resource in Area A sets price, all resources in Area A are paid $1.85 per kW-month.

There are two points to note about this example. First, modeling the locational constraint leads to price separation between the two areas. The clearing price in Area B is $4.80 per kW-month; the clearing price in Area A is only $1.85 per kW-month. By contrast, if there was *no* locational constraint modeled in the auction, then the FCA would have instead cleared at $1.95 per kW-month (clearing offers #1 through #11, to reach the ICR of 34,000 MW ICR). See Figure V-5.

Prices are higher in Area B where capacity is more valuable: There it serves both the system-level requirement as well as a locational reliability requirement (viz., it avoids the need for a transmission upgrade project). Prices are lower in Area A, where capacity serves only the system-level requirement.

CAPACITY SUBSTITUTION

A second point to note is capacity substitution. Clearing 2500 MW in Area B requires the auction to accept 1000 MW of new resources in Area B (Offers #17 and #18). Because these resources contribute to both the locational and the system level requirement, they substitute for 1000 MW in Area A. Specifically, they displace 1000 MW of capacity from offers #10 and #11 in Area A.

This capacity substitution effect is important for minimizing the true resource costs of capacity, as economic efficiency requires. Recall that to substitute for the transmission upgrade, the FCA needed to clear at least 1000 MW of new resources in Area B. Assume the true resource cost of these new capacity MRAs is the as-bid costs of Offers #17 and #18. From Table V-1, their total as-bid cost is \$4.6/kW-mo. x 500 MW + \$4.8/kW-mo. x 500 MW = \$4.7 million / month. However, clearing these two new resources displaced 1000 MW of resources in Area A from Offers #10 and #11, which have as-bid costs of \$1.9/kW-mo. x 500 MW + \$1.95/kw-mo. x 500 MW = \$1.925 million / month. Thus the true resource cost of procuring the capacity MRAs is the net, or difference between the (going-forward) costs of the new and displaced resources, which is only \$4.7 – \$1.925 = \$2.775 million per month.

MULTIPLE PRODUCTS

We point out these prices and costs to illustrate an important conceptual point. In a capacity auction with MRA constraints, the market is procuring *multiple products*. One product is a capacity MRA. It provides two services: Contributing to a locational reliability requirement (that would otherwise require a transmission upgrade), and contributing to a system-level reliability requirement (the ICR). The other product is capacity that is not an MRA. It provides only one service, contributing to the system-level requirement. The market clearing prices for the two products are different because one product is more valuable than the other, and is in scarce supply (when the locational procurement constraint is binding in the auction).

By the same logic, if there were two different MRA constraints modeled in the FCA, then there may be three different clearing prices.[32] The key concept here is that each capacity MRA requirement is a different product that serves a different purpose, insofar as it substitutes for a different transmission upgrade.

REMARK

In this example, the 1000 MW of new capacity resources in the constrained area is a substitute for a transmission solution. It is natural to assume this means the transmission facility would have had an import capability of 1000 MW. That is not correct. It may have a transfer capability of much more, or much less, than the additional capacity required of an MRA solution to the same locational reliability problem.

Two examples from earlier in the paper illustrate this technological point. In Section IV.B, Figure IV-3 illustrates a situation where solving the local reliability constraint requires either (a) 20 MW of additional transfer capability, or (b) 10 MW of additional capacity resources, at location A. In that example, an MRA solution requires *half* as much new capacity as the transmission solution's additional transfer capability.

[32] This statement assumes all MRA constraints in the FCA are one-directional (e.g., import-only) and separable. Separable means the constraints do not 'overlap' such that a capacity resource can simultaneously contribute to two (or more) MRA requirements. If the latter occurs, there may be more distinct clearing prices than the number of constraints plus one (for the rest-of-system).

In contrast, in Section V.B, Figure V-3 illustrates a situation where solving the local reliability constraint could be achieved with either (a) 10 MW of additional transfer capability (across line C-E), or (b) 43 MW of additional capacity resources (anywhere among locations B, E, or F). In that example the MRA solution requires over *four times* as much new capacity as the transmission solution's additional transfer capability.

The point here is that a MW of transmission capability and a MW of MRA capacity are not one-for-one substitutes to meet a transmission security constraint. Nothing in the foregoing example, nor in real applications of MRAs to the capacity market, would assume that. Rather, the relative capacity additions required of a transmission and an MRA solution are highly dependent on the transmission topology and the specific transmission security constraints that must be resolved.

Evaluating the total capacity MRAs necessary to satisfy the locational reliability requirement is a central purpose of the MRA assessment process discussed in Section V.B. The total amount of capacity resources that must contribute to a reliability constraint in order to avoid undertaking a transmission upgrade project—and not the transfer capacity of a new transmission facility per se—is what must be procured in the form of capacity MRAs.

SUMMARY

This example illustrates the economic logic underlying how the forward capacity auction can procure capacity MRAs to meet a locational reliability requirement and substitute for a transmission upgrade. The auction clearing logic illustrated in this example is conceptually similar to the existing local source requirement treatment in the FCA (if an import zone is modeled in the auction). The primary difference is the potential need to treat the capacity MRAs as a 'lumpy' option: If there are insufficient capacity MRAs offered in the auction to meet the constraint, then the transmission upgrade cannot be avoided. Whether, and in what form, the MRA constraint should be modeled in the FCA in that circumstance depends on whether the transmission project can be implemented in a scaled-down form or not.

Last, we emphasize that this is a simplified example for the sake of transparency. It abstracts from a number of additional issues that may be important in practice. One important simplification is the assumption that the reliability constraint between areas A and B limits imports into A, but does not limit exports from A. When both directions are potentially limited, the auction clearing process is more complicated. We discuss this and additional auction-related issues presently.

Issues and Challenges

Several factors introduce additional complications into the comparison of transmission and MRA solution cost-effectiveness using the forward capacity market. These include:

- Duration of locational constraints in FCA
- Implications for existing LSR zones
- Package alternatives
- Lumpiness of transmission and generation alternatives
- Multi-directional constraints
- Problems with the DCA format

The existing forward capacity auction mechanism can be extended to address each of these complications. However, in some cases, the effort required to do so will be significant. In addition, not all of these complications will necessarily arise for some time. That may enable the region to move forward with MRAs presently, and address the more challenging complications over time as they are expected to emerge. We elaborate on each of these issues and challenges below.

Constraint duration

Ideally, the constraints modeled in the FCA should reflect the same transmission security constraints that drive transmission needs assessments in the planning process. If these constraints would not be satisfied by the existing transmission and capacity resource configuration, then modeling them in the FCA would lead to their resolution either through acquisition of qualified MRAs or, if necessary, as a "backstop" transmission upgrade.

The next question that naturally arises is: After the problem is resolved, should the constraints be removed from future FCAs? In theory, the answer is no. Provided the underlying transmission security constraint is still part of the transmission system and evaluated in the planning process, it should remain part of the capacity auction clearing model. If it were to be removed, then a decision by a resource to exit the market that could precipitate a local reliability problem would not lead the capacity auction to procure replacement resources within the clearing process.

Keeping a constraint in the auction does not imply prices will always separate. After a transmission upgrade or MRA solution is implemented, the underlying constraint would typically be slack (that is, not binding) in future auctions. This may lead prices in future capacity auctions not to differ across areas, even though prices were different (because the constraint was binding) in a prior auction.

An analogy to the day-ahead energy market may be helpful here. In the energy market, there are *thousands* of transmission constraints. However, only a few of them are usually binding when the market clears each day. Most constraints are slack, and slack constraints do not affect the market's auction solution or the clearing prices. However, all of the constraints are present and modeled, because they must be satisfied to operate the system reliably (*i.e.,* satisfy transmission security).

This analogy also points to an implication for modeling updated locational reliability constraints in the FCA over time. The system's topology and planning contingency scenarios will change over time, as new facilities (both generation and transmission) are developed and old facilities retire. As the constraints modeled in the planning process evolve accordingly, the corresponding constraints incorporated in the FCM will need to be updated.

EXISTING LSR

Modeling locational reliability requirements using the approach discussed in this report has several important implications for the existing local source requirement (LSR) zones in the FCM. The central objective is to ensure that the treatment of LSRs is consistent with the way new locational reliability requirements are developed and incorporated into the FCA. Achieving consistency, in this context, would involve at least three important elements:

1. *Technical review of the existing definition of the LSR areas*, to ensure the constraints as modeled in the FCA reflect the underlying transmission constraints identified in the regional planning process.

2. *Modeling all LSR constraints in each FCA*, even if the constraint is slack (not binding) when the auction clears. This would provide consistency between the treatment of LSR zones and the duration of constraints discussed above.

3. *Employing equivalent analytic methods* and standards to identify transmission security constraints in the planning process and to determine the constraints modeled in the FCA areas.

The ISO is presently moving to implement item 2. Items 1 and 3 are related; while not conceptually difficult, they would require some effort by the planning process implement.

Last, we note that because topology changes over time, there is no obvious reason for the existing LSR zones to remain 'fixed' zones. Rather, they would become part of a list of locational reliability constraints that are modeled within the clearing process of the FCA, and updated periodically as new facilities (both transmission and generation) are developed or retire, in accordance with the regional planning processes described above.

CONSTRAINTS V. LOCATIONS

In the preceding example, we assumed—for simplicity—that all capacity resources in Area B are qualified to help resolve the local reliability requirement. This amounts to assuming that location alone is a sufficient qualification for a capacity resource to serve as an MRA and, potentially, receive a higher clearing price for contributing to both a locational and system-level reliability requirement.

In general, location alone will not be the sole criterion by which a capacity resource (whether new or existing) qualifies as contributing to a locational reliability requirement modeled in the FCA. As emphasized in Section V.B, some transmission security requirements may require capacity MRAs to meet response time requirements, or have reactive power supply capability, or meet other technical requirements in order to be viable substitutes for the transmission solution.

This means that, for example, two different capacity resources could be located near one another but only one qualifies as contributing to an identified reliability requirement. That is, qualification is based not on location per se, but based on the MRA requirements identified in the alternatives assessment process (*c.f.,* Section V.B). Only those capacity resources (both new and existing) that satisfy the requirements of an MRA for a specific reliability constraint would contribute, in the FCA clearing process, to the capacity requirement to meet the reliability constraint.

In summary, capacity resources that satisfy the MRA requirements for a specific constraint, and are cleared in the FCA to satisfy the specific constraint, would receive a clearing price that reflects the cost of satisfying the constraint. Clearing prices may be differentiated by factors other than locations alone, if the MRA reliability requirements are not based on location alone. This is important to ensure that the capacity market conveys price signals for capacity resources to locate *and* to invest in the technical requirements necessary to substitute for a transmission solution.

PACKAGE ALTERNATIVES

An additional general issue is that solutions to locational reliability requirements often may not break down neatly into 'capacity only' versus 'transmission only' solution alternatives. Rather, a combination of both may be most effective.

The planning process and MRA technical assessment will need to be able to identify whether a combination of transmission enhancements and additional capacity resources appears to be a promising solution to identified reliability needs. Unlike the examples previously, in that scenario new capacity and transmission upgrades are complements, rather than substitutes. This could create three (or more) feasible alternatives to resolve an identified reliability need. While this appears conceptually sensible, it would require additional functionality within the FCA that is not present today.

LUMPINESS

Transmission projects are 'lumpy'. By this, we mean that reducing a project's size (in MW) by half does not reduce its total cost by half. In addition, transmission projects cannot necessarily be scaled down, as a function of how many (MW of) capacity MRAs are cleared, and still yield a feasible solution to a transmission security requirement.

Lumpiness has important implications for the FCA clearing process. Most importantly, it means that the FCA may need to either accept several MRAs, or none at all, depending whether the transmission alternative is scalable or not.

Capacity resources may also be lumpy. Today, resources can offer into the FCA in a way that may be partially cleared, or as an 'all or none' offer that cannot be partially cleared. This reflects the fact that for many capacity resources, an offer price for one project size (in MW) would not be appropriate for a project at half the size.

The combination of lumpy transmission projects and lumpy capacity resources can produce situations where meeting an MRA reliability requirement in the FCA requires procuring *more* resources in an area than the locational reliability requirement specifies. One reason for this is that because capacity resources are lumpy, clearing more MW in an area may be necessary to make the MRA solution feasible—and avoid the need for a lumpy transmission solution.

The central implication is that locational reliability requirements modeled in the FCA need to be treated as minimum (or, if export limits, maximum) quantity constraints in the auction. It would not be advisable to treat the constraints as exact quantity limits in the auction. In an environment with lumpy transmission projects and lumpy capacity MRAs, treating procurement constraints as exact (instead of minimum) quantities may substantially complicate the FCA and prevent it from identifying viable MRA solutions.

DIRECTIONAL CONSTRAINTS

A more complex issue is that transmission security constraints can be bi-directional, rather than uni-directional. In the example earlier, for instance, we assumed a reliability constraint required either additional capacity in Area B, or additional import capability into Area B from Area A. This is an import-only, or *uni-directional* constraint. In general, however, a transmission line or interface has limits in *both directions.* In the planning process, these limits can bind in one direction in one set of contingency scenarios, and in the opposite direction in a different contingency scenario. In principle, if this occurs, both the export and the import constraints should be modeled in the FCA. If they are not modeled in both directions, then the capacity MRAs that are cleared may not turn out to be a viable alternative to the transmission project; or, alternatively, the FCA may clear resources that turn out not to be necessary for reliability at all.

Presently, the FCA's clearing procedure is not able to account for constraints that may bind in both directions. Although the details are complex, some of the issues that arise are illustrated by the following example.

SIMPLE EXAMPLE

Imagine two adjacent areas are connected by a limited transmission interface. Peak load in each area is identical, at 100 MW. The transmission security limit across the interface, as modeled in the planning process, is 10 MW in each direction. To make the point of this example transparent, assume there is load diversity between the two areas such that each area's load never exceeds 90 MW simultaneously. This implies only 90 MW of installed capacity is required in each area, as 10 MW can be imported from the other area.

Now suppose load growth is projected to increase peak demand in each region by 5 MW. As before, continue to assume the two regions do not exceed 90 MW of load simultaneously. Then 5 MW of additional transfer capability between the two regions could substitute for adding 5 MW to *each* area's capacity resources, and satisfy each area's reliability requirement. That is, the transmission solution and MRA solution alternatives are:

- *Transmission*: Add an additional 5MW of transfer capability between areas.
- *Capacity MRAs:* Add an additional 5MW of capacity resources in each area.

To procure the second and substitute for the first, how would the MRA constraints be formulated in the FCA? There would need to be one constraint defined on two areas' resources. It would require the FCA to clear 95 MW of capacity in one area *and* 95 MW of capacity in the other area—or, if 95 MW cannot be met in *either* area, to clear only 90 MW in *each* area. Why this? Consider what would happen if the constraint to acquire 95 MW in each area cannot be satisfied. To take an extreme example, suppose a total of only 94 MW of resources is offered in one of the two areas. Then it is not possible to clear enough MRAs to avoid the transmission solution. If the FCA clears the MRAs that *are* offered, we would potentially end up with *both* a transmission solution and capacity MRAs that are not, in fact, needed (because the transmission solution must be undertaken anyway).

To avoid this, the FCA would need to be able to clear MRAs, or not, in one area as a function of whether or not it is able to clear sufficient MRAs in another (inter-dependent) area. At a conceptual level, this is natural result of the interdependency of capacity and transmission in a network. As a practical matter, the current FCA's clearing engine is not capable of handling these types of constraints, and would have to be modified to provide this functionality. This type of enhancement is achievable, but would require a significant effort by the ISO to implement.

There are two additional observations to note. The first is that the MW of incremental capacity required (here, 10 MW total, with 5 MW in each area) is not, in general, twice the incremental transmission capability needed (here, 5 MW). In situations with bi-directional transmission constraints, the total amount of new capacity MRAs needed to avoid a transmission upgrade project depends, in a complex way, upon the frequency distribution of load in each area, topology and contingency scenarios, and most other inputs used in the transmission planning process. Thus the analysis that must be done prior to the auction to formulate bi-directional constraints can be quite involved, and the modeling may not produce intuitively transparent results.

The second complication is that, in more realistic examples, there can be *multiple* reliability constraints affected simultaneously by the transmission project. Recognizing all of the locational reliability constraints that can be simultaneously impacted by a transmission project, and modeling these impacts correctly in the FCA clearing process to procure capacity MRAs, is not a small endeavor. (See also the DCA format issues discussion, below).

The key insight here is that, from a planning standpoint, a transmission project may substitute for capacity resources in more than one area simultaneously. This occurs because, in reliability analysis, transmission security constraints can limit transfers in both directions (bi-directional constraints). The existing FCA design cannot accommodate bi-directional constraints, which is one of its notable shortcomings. This will need to be modified if the FCA is to produce capacity MRAs to transmission projects when transmission security constraints limit transfers between adjacent areas in both directions.

Descending Clock Auction (DCA) Format Issues

Throughout this paper, we have noted that to procure capacity MRAs to transmission solutions, it will be necessary to incorporate information on the same transmission security constraints identified in the planning process into the FCA. In general, these constraints do not correspond to drawing simple boundaries between areas of the system. Rather, they can create constraints that 'intersect' geographically, or that create overlapping, non-nested sets of resources that satisfy multiple locational reliability constraints.

For instance, the ISO's transmission planning process (and ISO real-time operations) respects both a north-south transmission security constraint (which is generally voltage limited), and an east-west transmission security constraint (which is generally thermal limited). Neither constraint is modeled in the FCM today. If both constraints were modeled in the FCM, then adding additional capacity resources in, say, one quadrant of the system could contribute to *two* transmission security constraints simultaneously.

These existing 'intersecting' constraints cannot be accommodated within the current FCA design. If an attempt was made to do so, application of the descending clock auction (DCA) format could produce incorrect results. By that, we mean that DCA is not capable of identifying and clearing the lowest-cost set of resources that meet both the locational and system-level reliability requirements in such situations.

Although the mathematical details are complex, the problem can be illustrated with the help of the next example. The implication is that modeling 'intersecting' or 'overlapping' constraints may require the ISO to drop the current descending clock auction format and adopt a new auction clearing engine, based on a sealed-bid auction format. This may not be necessary initially if intersecting constraints are not modeled, but would become necessary as more complex locational constraint patterns are modeled in the FCA.

Example

Consider an extension of the previous example, as illustrated in Figure V-6. Here we have introduced two import constraints: The 'northeast' region, consisting of resources in areas C and E, is import-constrained. In addition, the 'east' region, consisting of resources in area D and E, is also import-constrained. They are different constraints, however, and cannot be modeled as a single import-constrained area.

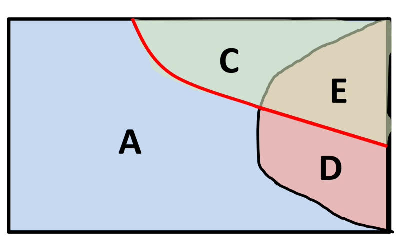

Figure V-6. *Two intersecting constraints. Area D and E is import constrained, and Area C and E is also import constrained.*

We call such situations 'intersecting' constraints. The terminology reflects that fact that the set of resources that can satisfy one constraint, and the set of resource that can satisfy the other constraint, are (mathematically) intersecting sets. In simpler terms, resources in area E can contribute to meeting *both* of the two locational reliability constraints.

ASSUMPTIONS

Table V-2 shows twenty (hypothetical) capacity offers submitted in the FCA and their locations. For convenience, these are the same twenty offers as in the previous example (Table V-1), but with revised locations. As before, the system-wide capacity requirement is 34,000 MW.

There is 1500 MW of existing capacity in Area E, but no existing capacity in Area C or D. We assume the regional planning process has identified a future local reliability (transmission security) constraint on power imports across the 'east' interface (the black line in Figure V-6), from areas A and C into areas D and E, that cannot be satisfied under modeled planning conditions due to projected load growth. The preferred transmission solution is to increase the transmission capability across this 'east' interface.

Table V-2. Twenty Capacity Auction Offers for the Two-Constraint Example

Offer #	Area	New or Existing?	Quantity (MW)	Offer Price ($ / kW-mo)	DCA Purchases	Optimal Purchases
1	A	Existing	10,000	1.500	10,000	10,000
2	A	Existing	5,000	1.550	15,000	15,000
3	A	Existing	3,500	1.600	18,500	18,500
4	A	Existing	4,000	1.650	22,500	22,500
5	A	Existing	5,000	1.750	27,500	27,500
6	A	Existing	3,000	1.800	30,500	30,500
7	E	Existing	1,000	1.810	31,500	31,500
8	E	Existing	500	1.830	32,000	32,000
9	A	Existing	1,000	1.850	***not cleared***	**33,000**
10	A	Existing	500	1.900	*not cleared*	*not cleared*
11	A	Existing	500	1.950	*not cleared*	*not cleared*
12	A	Existing	500	1.975	*not cleared*	*not cleared*
13	A	Existing	500	2.000	*not cleared*	*not cleared*
14	A	Existing	500	2.100	*not cleared*	*not cleared*
15	C	New	500	4.300	**32,500**	***not cleared***
16	C	New	500	4.500	**33,000**	***not cleared***
17	D	New	500	4.600	**33,500**	***not cleared***
18	D	New	500	4.800	**34,000**	***not cleared***
19	E	New	500	5.000	***not cleared***	**33,500**
20	E	New	500	5.100	***not cleared***	**34,000**

Note: All data in this table are hypothetical for example purposes.

Similarly, assume the regional planning process has identified a future local reliability (transmission security) constraint on power imports into the 'northeast' region, from areas A and D into areas C and E (the red line in Figure V-6). The preferred transmission solution is to increase the transmission capability across this 'northeast' interface.

Suppose now that the MRA requirements analysis indicates the 'east' reliability requirement could be satisfied with 1000 MW of new capacity resources in area D or E, instead of the transmission solution. As in the previous example, we formulate this locational reliability requirement in the FCA not as 1000 MW of *incremental* capacity resources in area D or E, but as 2500 MW of *total* capacity resources in area D or E. As before, assume (for simplicity) that all capacity offers in areas D or E, whether new or existing, contribute to satisfying the 'east' locational reliability constraint.

Similarly, suppose the MRA requirement analysis indicates that the 'northeast' reliability requirement could be satisfied with 1000 MW of new capacity resources in C or E, as an alternative to the 'northeast' transmission solution. Since there is 1500 MW of existing resources in E (and zero existing MW in C), this locational reliability requirement is formulated in the FCA as 2500 MW of *total* capacity resources in area C or E.

WHAT CLEARS?

In this example, what clears? The answer turns out to depend on what type of auction format is used. In general, a descending clock auction will get this 'wrong' – in the sense of not clearing the least-cost set of resources.

To see how, consider what resources would be cleared if we did use a descending clock auction. As before, consider which offers drop out as the descending clock auction proceeds. This can be done by walking up, from the bottom, the offers in Table V-2. At the start, a total of 3500 MW are offered in Areas D and E that can contribute to those areas' (combined) 2500 MW reliability constraint; the same holds for Areas C and E. As the price falls from its initial (high) starting value, the highest-priced offers will drop out. When the auction price falls (just) below $5 per kW-month, Offers #19 and #20 will have dropped out (de-listed in the auction).

At that point, there are only 2500 MW of resources left in Area D and E, which just satisfies the 'east' locational constraint. The remaining offers in Area D and E must be cleared to satisfy this locational constraint. These cleared offers are the two existing resources in Area E (Offers #7 and #8), and two new resources in Area D (Offers #17 and #18). See Table V-2.

Similarly, at that point there are only 2500 MW of resources left in Area C and E, which just satisfies the 'northeast' locational constraint. The remaining offers in Area C must be cleared to satisfy this locational constraint. The cleared offers are the same two existing resources in Area E (Offers #7 and #8), and two new resources in Area C (Offers #15 and #16). See Table V-2.

What happens in the rest-of-system? The auction continues. Because 3500 MW have already been cleared in Areas C, D, and E, the rest-of-system must clear only the ICR less

3500 MW, or 30,500 MW. This occurs when we reach Offer #6, which must be accepted to clear 30,500 MW in area A.

The set of all cleared and not-cleared resources under the descending clock auction are indicated in the second-to-last column of Table V-2.

PROBLEM

What is the problem here? The descending clock auction (DCA) has not picked the least-cost solution. If we sum up as-bid costs of all capacity resources that clear the DCA, as indicated in Table V-2, the total cost works out to $60.925 million per month.

However, a different solution is more efficient. The last column in Table V-2 shows that if we cleared a slightly different set of resources, the system-level and both locational reliability requirements could still be satisfied. The particular set of resources that would be cleared, as shown in the last column of Table V-2, has a lower total as-bid cost of $58.725 million per month. Bottom line: The DCA format is economically inefficient and accepts offers that are too costly. The excess cost of this inefficiency is $60.925 – $58.725 = $2.2 million per month.

What is the source of the inefficiency here? Table V-3 reveals the intermediate results. The key insight is that the two new supply offers in Area E, which are Offers #19 and #20, contribute to *both* locational reliability constraints. They substitute for twice as much capacity in the import-constrained areas as a whole: If Offers #19 and #20 are cleared, then it is not necessary to clear Offers #17 and #18 in area D, nor Offers #15 and #16 in Area C. These differences are highlighted in bold in the last two columns of Table V-2.

Table V-3. Comparing FCA Results

		DCA Solution		Optimal Solution
MW Cleared				
Area A		30,500		31,500
Area C	(*all new*)	1,000		0
Area D	(*all new*)	1,000		0
Area E	(*all existing*)	1,500	(*1000 new*)	2,500
Total Cleared (ICR)		34,000		34,000
Costs (Million $ / month)				
Capacity Cleared in A		49.100		50.950
Capacity Cleared in C		4.400		-
Capacity Cleared in D		4.700		-
Capacity Cleared in E		2.725		7.775
Total Costs		60.925		58.725

Note: All data in this table are derived from Table V-2. See text.

Note that, when Offers #19 and #20 are accepted in the import-constrained areas, it is necessary to clear an additional resource in the rest-of-system (Offer #9) to ensure the total system-level ICR is satisfied.

The descending clock auction gets things wrong because it looks only at *marginal prices,* not at *total costs.* The DCA skips over the new resources in Area E, because they have the highest prices. But clearing them requires less MW, in total, in the import-constrained areas. Reducing the total amount of MW procured in the high-cost, import-constrained areas is efficient. The DCA cannot do this because it is not capable of evaluating situations where capacity in one area (Area E) substitutes on a 2-for-1 basis for capacity in other areas (Areas C and D) that has nearly the same offer price.

SUMMARY

In the first FCA example in Table V-1, we considered a situation where capacity in an area (Area B) can help resolve a single locational reliability constraint. In that 'non-intersecting constraint' problem, the descending clock auction works properly. In the second example in Table V-2, we considered a situation where capacity in an area (Area E) can simultaneously help resolve *multiple* locational reliability constraints. In this 'intersecting-constraints' problem, the descending clock auction is not capable of properly clearing the FCA.

The practical implication we wish to illustrate here is that the current descending clock auction format is not capable, as a mathematical fact, of identifying the least-cost solution in such circumstances. As a result, as new locational reliability constraints are identified and modeled in the FCM, it may become necessary for the ISO to switch from the descending clock auction format to an optimization-based clearing algorithm to properly clear the FCA. This is achievable, but will require significant effort by the ISO to implement.

VI. OUTSTANDING ISSUES

This section discusses several additional outstanding issues that will be important to address in improving the alignment of planning and markets. The first and foremost is cost allocation for capacity MRAs with more granular locational capacity pricing. We then discuss several points concerning recourse and transmission costs, market mitigation, possible changes to capacity commitment periods for new resources, and analytic methods for evaluating system and local reliability constraints.

COST ALLOCATION

Procuring capacity resources as a substitute for transmission projects poses potentially difficult issues of cost allocation. The ISO has not identified a cost allocation method that resolves these difficulties at this point. Nevertheless, we can offer several observations on this issue that may facilitate discussion.

ASYMMETRIES

The difficulties of cost allocation for MRAs arise because of several asymmetries in the way transmission costs and capacity costs are allocated today. One asymmetry is that the costs of regionally-planned transmission upgrades are allocated to transmission providers, while the costs of capacity resources procured through the FCM are allocated to load-serving entities. Either way, both sets of costs are ultimately borne by New England electricity consumers. However, the intermediary wholesale-market participants may not be indifferent to who must bill the consumer to cover these costs.

The second asymmetry relates to local versus regional cost allocation differences for transmission costs and capacity costs. If a locational reliability requirement is resolved by developing a pool-supported transmission upgrade, the costs are allocated broadly across the region. Locational capacity costs are treated differently. In particular, if an existing local capacity zone clears at a higher price than the capacity price for the rest of the system, the additional expense incurred to meet the local capacity requirement is not allocated regionally. Although the details of the current local capacity cost allocation rules are complex, the concern is simple: There could be significant differences in how costs are allocated between an MRA solution and a transmission solution, when both are feasible alternatives to resolve the same reliability requirement.

The essential consequence of these asymmetries is that if new capacity resources are cleared in particular locations—as substitutes for regional transmission projects—there may be a significant shift in *who* bears the cost. Because the costs are allocated differently, this cost-shift may impede regional progress and agreement to pursue the most efficient solution overall. In economic terms, the current cost allocation rules do not align (i) an individual market participant's private interest in minimizing its allocated costs with (ii) society's broader interest in selecting the most cost-effective solutions.

NON-LOCAL BENEFITS

Much of the cost-allocation difficulty stems from the fact that capacity MRAs may benefit loads in geographic areas well beyond where the MRAs are acquired. Because of the capacity substitution effect, clearing additional capacity in an import-constrained area under an MRA solution—instead of adding additional transmission capability into the import-constrained area—can affect the capacity price that loads pay elsewhere in the system.

REST-OF-POOL PRICE

An example of this can be seen using the data presented earlier in the FCA numerical example, shown in Table V-1 of Section V.C. Consider, in the context of that example, the capacity price in Area A under the MRA solution and the transmission solution. Under the transmission solution, the capacity requirement in import-constrained Area B is satisfied with existing generators in Area B. These generators are inframarginal (they are Offers # 7 and #8 in Table V-1). That means the total system ICR and Area B's local capacity requirement are both satisfied by clearing all capacity offers at or below $1.95 per kW-month (this is Offer #11). In this case, there is one marginal resource pool-wide. Assuming the last resource cleared sets the market clearing price, the capacity price in all areas is $1.95 per kW-month.[33] Note that to determine Area A consumers' total expenditures under this solution, we must also add in their share of what the transmission project will cost.

Now consider the MRA solution. Here, because of capacity substitution, the last offer cleared in Area A is Offer #9, at $1.85 per kW-month. That means the regional clearing price for capacity in Area A—which, in this example, can be treated as the rest-of-system—is $.10 per kW-month *lower* under the MRA solution than under the transmission solution. Moreover, Area A consumers incur no costs for the regional transmission upgrade because the project is avoided under the MRA solution.

The central point to observe is that even if an MRA is procured in an area far from other loads in the system, the capacity substitution effect implies loads throughout the pool may experience expenditure reductions. This is true *in addition* to the savings that consumers in all areas would enjoy because the costs of the regional transmission upgrade, which all consumers bear, are no longer incurred.

LOCATIONAL COSTS

The cost-allocation asymmetries between MRA solutions and transmission solutions may become more striking when new capacity is required to meet the system-level reliability requirement (the ICR). To see this, consider a different example. In the Vermont/New Hampshire pilot study of MRAs, there is an identified reliability need for a transmission expansion in the Southwest New Hampshire area. Simulations indicate that an MRA solution would require adding approximately 150 MW of capacity to this area, which has a total load of approximately 250 MW.[34] Suppose further that, because

[33] It should be noted that, in theory, the most efficient outcome should be expected when the marginal resource that sets price is the first *rejected* offer, not the last accepted offer.

[34] *Nontransmission Alternatives Analysis – Results of the NH/VT Pilot Study* (May 24, 2011), p. 33-36, at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2011/may262011/nta_analysis.pdf [CEII].

of load growth system-wide, the FCA needs to clear an additional 150 MW of new capacity to meet the system-level ICR. In this case, the new capacity MRAs would perform a double-duty: they are not only a solution to the locational reliability requirement, they also solve the system-level reliability requirement.

In this situation, expecting consumers in this small area to bear the incremental cost of the 150 MW of new capacity—recall this area has only 250 MW of load—may not align different loads' benefits and costs. Load growth system-wide, not just in this local area, is the driver for the greater system-wide ICR. Moreover, since this local area has only 250 MW of load to begin with, the disparity between the capacity charges to consumers in the area where the MRA is located and the capacity charges to loads elsewhere in the system could be great.

In contrast, if the transmission solution was undertaken instead, and the 150 MW were acquired elsewhere in the pool, then the (assumed) higher total costs of *both* the transmission solution and the new capacity would be borne by load throughout the region. These perceived inequities in who bears the costs of a MRA solution versus a transmission solution could produce opposition to procuring MRA by loads in the areas where it would be located, even if MRAs are the most efficient solution overall.

IMPLICATIONS

There are many ways to allocate the costs of capacity MRAs solutions. A primary concern of the ISO is that asymmetries between cost allocations under transmission solutions and MRA solutions, if they are significant, will impede regional consensus to pursue more efficient solutions overall.

To avoid this outcome, it may be desirable for regional discussions to focus on certain principles for cost allocation. One such principle is that the cost allocation rules for capacity costs should align market participants' individual financial incentives (*viz*., to minimize their individual payments) with the regions' broader interest in indentifying the best solutions to locational and system reliability requirements. As a practical matter, this principle calls for each load area to not be worse off if an MRA is selected instead of a transmission solution.

Nevertheless, it may be a challenge to implement even this seemingly-appealing principle, because of uncertainty over how the capacity market would clear under a different alternative. Moreover, a cost allocation consistent with this principle may not be easily reconciled with the existing net regional clearing price methodology for cost allocation among capacity zones.

In sum, the ISO anticipates that identifying a broadly satisfactory resolution to the challenges of cost allocation with MRAs may require extensive stakeholder guidance and discussion.

RECOURSE

One issue that arises when procuring capacity resources instead of transmission reliability projects is uncertainty over the relative costs of each solution. In particular, if capacity MRAs are a potentially high-cost solution to a locational reliability problem, then it would be sensible for the ISO to be able to perform some type of 'no regrets' check before approving a solution approach.

Is there a way to enhance the forward capacity market and resource planning process so that MRAs are not procured if their costs are unexpectedly higher than a backstop transmission solution? In principle, the answer is yes. This would involve incorporating information on the projected 'avoided cost' of the transmission solution into the FCA's clearing mechanism. In practice, however, the ISO believes it would be difficult to perform this economic comparison accurately because of the many uncertainties inherent in the planning process.

To explain the issues involved, we first summarize this 'recourse' concept in an idealized context. We then describe some of the difficulties that would be have to be overcome to apply this in practice.

CONCEPT

Imagine, for the sake of example, that the final cost of a transmission project was known in advance of when capacity MRAs are procured in the FCA. In that case it is possible for the FCA to clear the capacity MRAs if they are the lower cost solution, and not to clear them if otherwise.

To illustrate, consider again the FCA example from Table V-1 in Section V.C. In that example, we assumed a transmission project could be avoided through the procurement of 1000 MW of new capacity resources in Area B. For the offer values and cleared resources shown in Table V-1, the total resource cost (as-bid) of all cleared capacity offers in Areas A and B works out to $58.375 million per month.

In principle, within the auction itself, it is possible for the FCA to evaluate what total resource costs would be if the transmission solution is pursued instead. In the same example, if the transmission solution is pursued, then the locational reliability constraint in Area B would not be binding; the least-cost method to satisfy the ICR is to clear the first 11 offers. The total resource cost (as-bid) of doing so works out to $55.6 million per month. In this example, the FCA should clear the capacity MRAs if the appropriate (avoided) cost of the transmission solution is greater than the difference in total capacity costs, that is, if it is more than $58.375 – $55.6 = $2.775 million per month.

The recourse option is that the FCA could, in principle, perform this check. The concept is that if the additional costs incurred to clear the capacity MRAs turns out to be unexpectedly high, relative to an avoided cost 'threshold' assigned to the transmission solution, there would be recourse not to clear the capacity MRAs and instead to develop the transmission solution.

PRACTICALITIES

As a matter of economic theory, this is a rather tidy comparison concept. In practice, however, the heterogeneous nature of transmission and capacity resources—as well as the uncertainties regarding transmission project costs—would make this a difficult exercise to carry out with much confidence in the results. There are several reasons why.

HETEROGENEITY

One set of complications is that any mechanism—whether performed through the FCA or otherwise—will not identify the most cost-effective solution by comparing only solutions' capital costs. For example, both capacity resources and transmission projects may have efficiency impacts in the energy markets that reduce total energy production costs (such as reducing congestion, or out-of-market unit commitments for reliability, and on). These impacts may differ between MRAs and transmission projects. Either could also increase energy production costs, potentially.

There are also potentially significant longevity differences between a transmission investment and MRA capacity resources. With long-lived assets, in a world of perfect information, the economic comparisons would simply be made on a net present value basis. In the real world, there is no simple way to 'adjust' for the differences in the longevity of transmission assets and those of capacity resources offered in the FCM. There is also a potentially-complicated levelization necessary to align the five-year commitment period offered new generation with the much longer cost-recovery period that applies to cost-of-service transmission assets.

UNCERTAINTY

Perhaps the most difficult issue is the uncertainty surrounding transmission project costs at the time this decision would have to be made. Preferred transmission project cost estimates assembled in a Transmission Solutions Study have a typical standard for accuracy of between –25% and +50%. In practice, this can be a fairly wide range in dollar terms. For example, the Pittsfield-Greenfield transmission upgrades discussed earlier (p. 28) have a projected capital cost of \$130 million, but this should be interpreted as a projected final cost in the range of \$93 million to \$208 million—as the transmission solution study indicates. This rather broad range introduces considerable uncertainty into any prospective evaluation of whether MRAs would be lower cost (whether preformed through the FCA or any other process).

The uncertainty in transmission project costs can create errors both ways. If the projected cost is too high, it could induce capacity MRAs to enter that have higher cost than the true cost of transmission solution, which would be inefficient. If the projected transmission cost is too low, it would deter MRA entry that is cost effective, which again would be inefficient. Either outcome undermines the objective of identifying more cost-effective solutions to the region's investment requirements.

The bottom line on these considerations is that the ISO believes performing a cost-benefit analysis on procuring capacity MRAs (relative to backstop transmission solutions) would be extremely difficult to do. Despite the appeal of a formal recourse option embedded within the FCA, the uncertainties inherent in estimating appropriate ‘avoided costs’ for transmission projects means the region would not be able to expect much confidence in the economic accuracy of such an endeavor.

Initial Capacity Commitment Period for MRAs

New generation capacity is able to elect up to a five-year initial capacity price commitment upon clearing the FCA. In contrast, the costs of a transmission upgrade are generally recovered, by the regulated transmission owner, over much longer periods. This difference raises the question of whether new capacity resources that substitute for a transmission upgrade should be afforded a longer initial price commitment period than the current five year maximum.

There are pros and cons to such a change, and perspectives may differ among market participants. Here we discuss some of the important considerations.

Price reversion effects

One significant issue is the possibility for quick reversion of capacity prices in a locational area to excess capacity conditions after an MRA enters. In some cases, the areas in which MRAs may locate to resolve a locational reliability requirement may be similar to existing capacity zones. In others cases, however, the geographic size of the area may be much smaller. Because capacity additions tend to be ‘lumpy’, new capacity MRAs may lead total supply to exceed the locational constraint in years following the capacity addition. Even if the constraint remains modeled in the FCA indefinitely, ‘lumpy’ capacity MRA additions will lead the constraint to be slack (*i.e.,* non-binding) in future FCAs. A slack constraint means prices may not separate between areas, and therefore the price in a locational area where MRAs are added may quickly revert to the system-wide clearing price.

New capacity MRAs will likely anticipate this price reversion effect, which will result in higher initial (new) capacity offers to ensure a long-lived new capacity resource expects to (at least) break even. Under current rules, a new generation MRA can elect a five-year initial commitment period. However, it may be the case that five years at the initial clearing price may not be sufficient to attract satisfactory interest from potential new entrants. The market may produce more offers and greater entry if new capacity MRAs receive a longer commitment period, given an anticipated future reduction in the local capacity clearing price post-entry.

Risk

Why would extending the initial price commitment period potentially attract additional entry? The reason is that it reduces the new entrant’s risk. Locking in the price associated with a resource’s capacity revenue over a longer period reduces the entrant’s uncertainty regarding its future revenue streams. This includes the risk of a larger price reversion effect than initially anticipated. Reduced risk lowers the cost of acquiring initial financing to undertake the new capacity project, making it easier to finance new entry. In turn, lowering the cost of entry will, as a general principle, increase the number of potential entrants that may offer MRAs. (Increasing the attractiveness of entry will also help address market power mitigation concerns, addressed further below).

SUBSTITUTION

There is a potential concern with extending capacity commitment periods for new resources, if applied only to MRAs. If otherwise-identical new capacity resources receive different initial capacity price commitment periods depending whether it is an MRA or not, the difference in commitment periods could create inefficient capacity substitution.

Imagine, for example, that there are two new identical capacity resources that independently determine, if faced with a five year initial commitment period, their minimum (*i.e.,* breakeven) capacity offer would be $6 per kW-month. Now imagine that *one* of the two resources is instead offered a ten year initial commitment period. Its costs, by assumption, have not changed; nor has the present discounted value of the cash flows needed to just break even. However, the longer commitment period affords it a greater period of time over which to recover (the present discounted value of) these cash flows.

That introduces an asymmetry that can be inefficient. Specifically, while the resource with the five year commitment period requires $6 per kW-month over five years to just break even, the identical resource with a ten-year commitment period might require only (say) $5 per kW-month to just break even. In the FCM, the auction will pick the 10-year resource even though the true costs, in present value terms, of both new resources may be identical. Worse yet, if the resources were not identical and the one with the 10-year initial commitment was actually a higher-cost, less-efficient resource, the FCA might still pick it—selecting the less efficient resource overall.

The central point to observe here is that the market may experience inefficient capacity substitution if similar new capacity resources are offered different initial price commitment periods, depending whether they are MRA solutions or not. This implies that any change in the initial capacity commitment period may need to be applied in the same way for all new generation, rather than extended only to new capacity MRAs.

MARKET POWER MITIGATION

One concern that arises with the introduction of additional constraints into the FCM is market power. As noted previously, incorporating the transmission security constraints identified in the planning process into the FCM can create MRA areas that are as large as existing zones, are sub-zonal, or could be as small as a limited set of network nodes (*e.g.,* taps or substations). As the set of admissible interconnection points in which an MRA must be located shrinks, the number of potential entrants that can site a new resource in the admissible areas is likely to decline.

At present, the Internal Market Monitor undertakes extensive, resource-specific reviews to establish reference bids for capacity resources. These reviews and offer requirements help ensure a competitive outcome in the FCM. These reviews may become more important if MRAs are required in small areas, but the ISO believes the Market Monitor's scope of authority today is sufficient to meet this challenge.

This issue is inter-related to the duration of the initial commitment period, discussed above. As the length of the initial price commitment period increases, the attractiveness of entry by new capacity increases, and the impact of the 'visible hand' of market mitigation is lessened. In effect, longer commitment periods increase the intensity of pre-entry market competition within the FCA; after entry occurs, the fact that only a few resources entered does not convey market power in subsequent FCAs if they are effectively under a longer-term, fixed price capacity contract. Thus, to a certain degree, concerns over the need for greater market mitigation may be alleviated if the region extends the initial capacity price commitment period for new resources.

Nevertheless, the process of identifying locational reliability constraints will produce new information that may affect participants' behavior. Existing resources in an area where an MRA would be required to locate will no doubt learn, through the results of the open, ISO-driven MRA technical assessment process (*see* Section V.B), that certain existing resources contribute to a locational reliability requirement. That may provide these resources with an opportunity to seek to obtain a higher price for their existing capacity. Entry should limit existing resources' ability to do so, but the markets' response may take time to emerge.

Last, it is not clear that a capacity MRA could be procured through competitive means if competition is severely limited by the set of requirements. Of particular concern here are the implications of existing inter-connection rights, and the costs to a new resource of satisfying existing deliverability requirements if it must be sited in a narrow area to meet the MRA locational requirements. If the underlying locational reliability requirement is prompted by a potential generator's retirement, these issues may be addressed through application of (or revisions to) existing "conditional qualification" provisions of the FCM. In effect, this would enable the ISO to conditionally qualify multiple new capacity resources for the same interconnection 'space', provided an existing resource retires. Making this work may require revisions to the interconnection rights and obligations, so that interconnection 'space' smoothly transfers to the winner of the FCA when an MRA solution clears.

STANDARDS AND ANALYTIC METHODS

Today, the ISO's planning process applies different standards and analytic methods to determine the system-level resource adequacy requirement and to determine locational reliability requirements. The standards and methods are also somewhat different for local capacity zones modeled in the FCM than for locational reliability requirements studied in transmission needs assessments. It would be desirable for these different methods to be better aligned. Over time, the differences may create inconsistencies or undesirable results as additional constraints are added to the FCM to enable MRAs.

TSA REQUIREMENTS

In the planning process, locational reliability requirements are assessed based on N-1 and N-1-1 transmission security standards. (*See* Section IV.B, p. 26). This is a deterministic analysis: A lengthy sequence of scenarios is evaluated, one by one, to assess whether the transmission system (under the modeled conditions) is able to deliver power from where it is produced to where it is consumed while satisfying all transmission security constraints (thermal, voltage, and stability).

Throughout this report, we have presumed that MRA requirements—admissible locations, megawatts, and any other requirements—would be derived from the same standards and methods. This is important, as it is necessary to ensure that the MRAs are able to resolve the locational reliability requirements and avoid a backstop transmission solution.

EXISTING ZONES

As discussed previously, the existing local source requirements (LSR) for capacity zones are not determined quite the same way. Zone import limits are determined using a simplified transmission security analysis. A loss-of-load expectation model is also applied to estimate capacity requirements in the zone. The results of this hybrid procedure are not, in general, the same as the results that would be obtained with a full transmission security analysis methodology, as would be used to determine MRA requirements.

Going forward, it is important to employ equivalent analytic methods and standards to assess the capacity required in existing capacity zones and in other areas where capacity MRAs are procured. The reasons this is important are two. The first is to ensure that the locational constraints modeled in the FCA provide internally-consistent price signals regarding the value of capacity in different areas. The second is to ensure that the locational constraints modeled in the FCA areas reflect the same transmission security standards that drive the choice of transmission solutions. If the latter is not satisfied, then MRA solutions may not, in fact, be substitutes for transmission solutions to solve a locational reliability requirement.

While not conceptually difficult, applying the same analytic methods to determine capacity zones and LSRs as used in planning TSA studies would require some effort by the ISO implement. The overarching purpose of aligning these standards is to ensure analytic and economic consistency for all locational constraints modeled in the FCM.

SYSTEM-LEVEL ADEQUACY

A related issue concerns the analytic methods and standards used to determine the system-level reliability requirement. Presently, the regional planning process studies the system-level resource adequacy requirement based on a probabilistic analysis for forecasted peak demand, relative to available capacity. The objective is to add capacity resources as needed to maintain a so-called loss-of-load-expectation (LOLE) below a pre-specified threshold. By doing so, it is intended that the chance system-wide demand will exceed system-wide supply will be kept to an acceptably small value.

In implementation, the LOLE-based analytic methods presently used to determine the system-level requirement ignore the transmission network. That approach may produce less than ideal price signals of reliability needs. Conceptually, the amounts and locations of efficient capacity investment should be based on a trade-off between the marginal value of lost load (which is likely quite high) and the cost of incremental system resources *at their highest value location*. Without information on the highest value location, the system-level resource adequacy calculation will potentially produce results that are not economically efficient.[35]

The central point here is that it would be desirable to coordinate the standards and analytic methods used to determine both locational and system-level reliability requirements, so that they produce sound economic price signals for capacity investment.

[35] In recent years, there has been considerable progress on this problem in the engineering literature. *See*, e.g., A. Rudkevich, A. Lazebnik, and I. Sorokin, "Economically Justified Locational Criteria of the Security of Supply," 9th International Conference on European Energy Market (EEM12), May 2012; F. Zhao, E. Litvinov, M. Negrete-Pincetic, and G. Gross, "Probabilistic Resource Planning with Explicit Reliability Considerations," *Proceedings of 2010 IREP Symposium-Bulk Power System Dynamics and Control VIII (IREP)*, August 1-6, 2010, Buzios, RJ, Brazil.

VII. Conclusions

Over the past decade, the regional planning approach to identifying reliability needs and then building transmission to address those needs has been successful in meeting the power system's reliability requirements. However, this approach does not enable market-based resources to have the same opportunity to meet these reliability needs. Considering market-based resources as alternatives to cost-of-service transmission projects could, in some circumstances, be a more efficient means to meet the region's future reliability requirements.

Three changes are necessary to enable market-based resources to be more effective alternatives to backstop reliability transmission projects. First, the timing of market procurement of resources needs to be better aligned with the transmission planning process. Second, market participants must have appropriate information to develop the market solutions that could address a reliability need identified in the planning process. Third, and most importantly, the market needs to send appropriate price signals to attract investment that could alleviate the need for the transmission solution.

Currently, the regional planning process does not identify locational reliability requirements far enough in advance of the year of need to enable the market to respond before substantial investments are made in the backstop transmission solution. Advancing the identification of potential future reliability issues will be necessary for market participants to respond to reliability needs with competitive alternatives. This will require substantial but achievable changes to the planning process.

Not only does region need to better align the timing of markets and planning, additional information must be provided to the market so participants can respond with resources that will satisfy identified reliability needs. The planning process, with the recent New Hampshire/Vermont planning studies, has just begun to develop the methods for providing this information. To enable the market to respond with resources that solve locational reliability problems, the additional information may need to be specific and tailored to the identified reliability need (*e.g.,* locations, quantities in MW, and other technical requirements). These requirements must be closely coordinated with the reliability needs identified in the planning process and that would be resolved by a transmission solution; failure to ensure this coordination could lead to the development of resources that do not actually address the underlying reliability needs.

Finally, the market needs to provide the appropriate price signals to induce market participants to offer market resource alternatives to backstop transmission projects. To provide these price signals, the market needs to be locationally differentiated to a greater extent than today, so that resources are procured in the proper locations. By identifying the locational needs in the market, potential developers of competitive alternatives will know what is required to meet a locational reliability requirement and will have adequate financial incentive to develop those projects. With enhancements to the forward capacity market, competition to develop projects can assure that the most cost-effective MRA solutions are pursued.

Although the details of enhancing the markets and planning process to enable MRA solutions may appear extensive at first, the ISO believes this is a path that will benefit New England overall. Importantly, progress can be made first by focusing implementation efforts on situations with the largest potential benefits from procuring capacity MRAs to transmission projects. Many of these initial situations will not pose all of the complexities described in this report because they involve conceptually straightforward problems and the addition of simple constraints to the FCM. These would function much like the existing local capacity zone structure, and address a broader set of reliability problems with market resources while reducing the need for cost-of-service transmission projects.

Of particular importance will be cases prompted by potential generation retirements. Here the ISO expects capacity MRAs to provide a double-duty service: Not only would they satisfy a potential need for new capacity resources to maintain the system-level resource adequacy requirement, but they can reduce the need for backstop transmission projects resulting from key generation retirements.

Looking forward, there are a number of issues and challenges to be resolved before the alignment of planning and markets can be achieved. These include enhancing the planning process to more regularly identify specific MRAs that would resolve reliability needs, modifying the FCA with locational constraints that would result in the purchase of MRAs where appropriate, and allocating the costs of MRAs in a way that aligns the incentives of regional stakeholders with the goal of meeting reliability needs in the most efficient way.

The ISO is committed to addressing these challenges through an open and transparent stakeholder process. Good communication and thorough discussion will be essential at every stage, from development of criteria for identifying MRAs, to sorting through MRA cost allocation, to actually defining a specific need to be met in the forward capacity market. The ISO is confident that the region can improve the alignment of planning and markets to better enable market resources to solve reliability problems, and to ensure the region’s reliability needs are met in the most efficient way possible.