Draft Chapter for NEDRI Final Report
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Opportunities for Load Participation in Contingency Reserve Markets

Summary:

This chapter focuses on policies and strategies that are required to encourage customer loads to participate in providing reliability services in contingency reserve markets. Potential benefits include increased reliability because generation can be freed up to provide energy and reduced costs to power system customers because the pool of contingency resources is increased and there will be increased price competition. However, encouraging demand participation requires a careful review of existing reliability rules and market designs to ensure they do not unfairly exclude resources that can provide valuable services to the grid. To further that objective, NEDRI offers the following recommendations:

- ISO New England (ISO-NE) should design and implement markets for all three contingency-reserve services as soon as possible

- ISO-NE, working with NPCC, should ensure that the reliability rules and requirements related to DCS and contingency reserves are technology- neutral and performance-based. NPCC should publish engineering/economic analyses used to justify reliability rules.

- ISO New England should review its contingency reserve metering and communications requirements and consider less frequent (and costly) data recording and reporting requirements for loads; any revision of these requirements must be contingent on the continued maintenance of reliability requirements.

- There should be a market potential study and pilot demonstrations that assess the benefits and costs of using large and small loads to provide contingency reserves. The pilot demonstrations should be reflective of the actual system logistics involved in aggregating and incorporating numerous small load resources. As part of the pilot, load research protocols for aggregations of small loads should be developed and evaluated, which may serve as an equivalent alternative to traditional performance measurements used for generators. Candidate sponsors to conduct these studies and pilot demonstrations include US DOE, ISO-New England, and New England utilities.

I. Introduction and Background

Direct participation of retail loads in wholesale power markets is likely to improve reliability, expand the scope of these markets, lower prices, and reduce the opportunities for the exercise of market power. Encouraging such demand participation requires a careful review of existing reliability rules and market designs to ensure they do not unfairly exclude resources that can provide valuable services to the grid. This chapter, complements the chapter on Regional Demand Response programs to facilitate short-term demand response, and focuses on issues and opportunities facing New England if retail loads are to participate effectively in certain ancillary services markets: 10-minute spinning reserve, 10-minute non-spinning (supplemental) reserve, and 30-minute (replacement) reserve.[1] The chapter describes specific ancillary services, summarizes the design and results for contingency reserves markets in the Northeast, the technical and performance reliability requirements imposed on resources that provide these services, the characteristics and challenges facing retail loads that might provide these reserves, and several recommendations for the ISO, reliability organizations, and New England policymakers.

The NEDRI Process

The NEDRI stakeholders discussed load participation in Contingency Reserve Markets over a twelve month period, beginning with Framing Paper on Demand Side Resources and Reliability (April 2002),[2] technical papers on retail load provision of ancillary services (Feb. 2003), and recommendations on policies and strategies to facilitate participation by customer loads (Feb. 2003).[3]

What are Ancillary Services?

Ancillary services are those functions performed by the equipment and people that generate, control, and transmit electricity in support of the basic services of generating capacity, energy supply, and power delivery. These services are required to respond to the two unique characteristics of bulk-power systems: the need to maintain a balance between generation and load in near real-time and the need to re-dispatch generation (or load) to manage power flows through individual transmission facilities. Table 1 lists the key real-power ancillary services that ISOs generally buy in competitive markets.

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[1] The Regional Demand Response Program chapter includes ISO markets for day-ahead and real-time energy, capacity, and "emergency resources", while this chapter focuses on contingency reserves. Key differences include level of market development and technical and performance requirements that effectively exclude load participation, which caused us to treat these regional, wholesale markets in separate chapters.
[2] E. Hirst and R. Cowart, "Demand-Side Resources and Reliability," NEDRI Framing Paper #2, March 2002
[3] B. Kirby and E. Hirst, "Technical Issues related to Retail Load Provision of Ancillary Services", NEDRI technical paper, Feb 2003 and "Opportunities for Demand Participation in New England Contingency Reserve Markets," Feb. 2003.

Table 1. Definitions of the real-power ancillary services

Market	Description
Regulation	Generators online, on automatic generation control, that can respond rapidly to system-operator requests for up and down movements; used to track the minute-to-minute fluctuations in system load and to correct for unintended fluctuations in generator output to comply with NERC CPS
Spinning Reserve	Generators online, synchronized to the grid, that can increase output immediately in response to a major generator or transmission outage and can reach full output within 10 minutes to comply with NERC DCS
Supplemental reserve	Same as spinning reserve, but need not respond *immediately;* therefore units can be offline but still must be capable of reaching full output within the required 10 minutes
Replacement reserve	Same as supplemental reserve, but with a 30-minute response time, used to restore spinning and supplemental reserves to their pre-contingency status

The North American Electric Reliability Council's (NERC 2002) Policy 1 on "Generation Control and Performance" specifies two standards that control areas must meet to maintain reliability in real time. The Control Performance Standard (CPS) covers normal operations and the Disturbance Control Standard (DCS) deals with recovery from major generator or transmission outages. System operators rely mainly on regulation resources to meet CPS. Because provision of regulation service requires a change in output (or consumption) on a minute-to-minute basis and, therefore, requires special automatic-control equipment at the generator (or customer facility), it seems unlikely that many retail loads will be able to or want to provide this service.

The three contingency-reserve services (spinning, supplemental and replacement reserves) are used to help control-area operators meet the DCS requirement. The DCS is a performance measure and specifies what must be accomplished without specifying how that goal must be reached.[4] DCS requires that the electric system recover from a major outage within 15 minutes; a major outage is defined as an event between 80 and 100% of the largest single contingency.[5] Spinning reserve is the most valuable service, and therefore generally the most expensive, because it requires the generator to be on line and synchronized to the grid.[6] Supplemental reserve is less valuable because it does not necessarily provide an *immediate* response to an

[4] Policy 1requires that: "Each Control Area or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the NERC Disturbance Control Standard. As a minimum, the Control Area or Reserve Sharing Group shall carry at least enough Contingency Reserves to cover the Most Severe Single Contingency."

[5] Although NERC requires recovery from a major disturbance within 15 minutes, the control-area operators require the resources providing contingency reserves to respond fully within 10 minutes. The extra five minute is often needed by the operators to decide whether a major contingency has occurred and, if so, how best to respond.

[6] Because such generators are online, they can begin responding to a contingency immediately; that is, their governors sense the drop in Interconnection frequency associated with the outage and begin to increase output within seconds.

outage. Both spinning and supplemental reserves must reach their committed output within 10 minutes of being called by the system operator. Replacement reserves are less valuable because it need not respond fully until 30 minutes after being deployed.

The *Operating Reserve Criteria* of the Northeast Power Coordinating Council (NPCC 2002) tends to be more prescriptive in its requirements for each type of reserve (Table 2). NPCC requires that the resources providing reserves be able to sustain full output for at least 60 minutes. The system operator uses this time to acquire and deploy replacement reserves. NPCC also requires the system operator to restore the 10-minute reserves within 105 minutes of when the DCS event occurred, to be ready to respond to another major outage.

ISO-NE typically acquires about 600 to 700 MW each of spinning reserve, supplemental reserve, and replacement reserve.[7] The largest contingency in New England is generally a nuclear unit or the power flowing from Hydro Quebec into New England over a DC transmission line. The amounts vary from hour to hour and from month to month; the total amount of reserves acquired during January 2002 ranged from 1270 to 2000 MW, with an average of 1730 MW.

Table 2. NPCC contingency-reserve requirements

	10-minute reserve	30-minute reserve
Amount required	100% of first contingency	50% of second contingency
Maximum response time	10 minutes	30 minutes
% of reserve that must be spinning[a]	25 to 100	0
Minimum sustainable time	1 hour	1 hour
Maximum restoration time	90 to 105 minutes[b]	4 hours

Notes:
[a]The percentage of 10-minute reserve that must be spinning (synchronized) depends on the performance of the control area in recovering from DCS-reportable events within the required 15 minutes.
[b]The maximum time to restore reserves (from the start of the event) is 105 minutes for a DCS event (a loss greater than 500 MW) and 90 minutes for a smaller deficiency.

Markets for Contingency Reserves

In its Standard Market Design proposal, FERC (2002a) would require day-ahead markets for spinning and supplemental reserves, but not for the 30-minute replacement reserve; these

[7] In May 2002, ISO-NE increased its purchase of replacement reserves from about 600 to 1200 MW to make explicit the ISO's former implicit commitment of resources day ahead to meet its second-contingency requirement. New England needs these extra reserves because the region has little quick-start (e.g., combustion turbine) capacity.

markets would be open to demand-side resources as well as generators. FERC proposes that these markets be integrated with the energy market; this implies that the market-clearing price will reflect both the availability bids of the resource plus the location-specific opportunity cost of the resource. FERC also proposes operation of real-time markets for ancillary services. These real-time markets would differ from the day-ahead markets in that potential suppliers would not be permitted to submit availability bids. In other words, the prices for each reserve service in real time would be a function only of the real-time energy-related opportunity costs. Current market design for ancillary services varies by ISO.

New England

ISO-NE has experienced problems with its markets for reserve services, particularly during the initial months of operation (May-August 1999). Complications in the design of ISO-NE's day-ahead unit-commitment and its 5-minute security-constrained dispatch prevented it from notifying beforehand the winning bidders in its ancillary-services markets. As a consequence, generators did not know whether they were "selected" to provide operating reserves until after the fact. In addition, the ISO might, during a major outage, call upon units that were not selected to provide reserves, and therefore they did not get paid for providing the service. In August 1999, ISO New England filed emergency market revisions with FERC to address problems during the first three months of operation.8

In 2002, the annual cost to New England of the three reserve services was about $30 million. Between January 2000 through December 2002, reserve market prices in New England have been consistently below $2/MW-hr, averaging $1.15 for spinning reserve, $2.08 for supplemental reserves, and $0.81/MW-hr for replacement reserve. (During 2002, the prices averaged $1.68, $1.67, and $1.10/MW-hr, respectively). However, historic prices paid for reserves by ISO-NE may not be a good proxy for the actual value of reserves because of design problems in the reserve markets.

New England implemented a new, improved market design in March 2003, based on the design now operating in PJM. However, this new market system will not include PJM's two-part market for spinning reserve (see discussion below) (Patton 2002). ISO New England has not yet decided on the structure of its markets for contingency reserves and, therefore, may have no operating markets for any of the contingency reserves until mid- or late-2003.

New York

The New York ISO (NYISO) acquires roughly 600 MW per hour of each of the three reserve services and spent about $29 million on contingency reserves during 2002, an amount

[8] ISO-NE (1999) concluded that "four of the [ISO] markets, ten-minute non-spinning reserve, 30-minute operating reserve, operable capability, and installed capability are fundamentally flawed They do not require delivery of any physical product, and there is no difference in the costs or risks incurred by those participants who receive payments in and those who do not. As a result the only economically rational bid in the market is a bid of zero (to ensure selection in the hope there is any positive price) or a bid that is an attempt to set the clearing price."

comparable to New England. NYISO operates an integrated set of markets for energy, real-power ancillary services, and congestion management (Kranz, Pike, and Hirst 2002). Because of the severity of transmission constraints in New York, especially in New York City and Long Island, New York's reserve markets have three zones. Between January 2001 through December 2002, the prices of spinning, supplemental, and replacement reserve in New York averaged 2.74, 1.69, and \$1.16/MW-hr, respectively.[9] This ordering of prices is consistent with the value of each service and might be a more reasonable indicator of relative pricing of various ancillary services in a well-functioning market.

PJM

Until December 2002, PJM had no markets for contingency reserves. Any generator committed for service by PJM is guaranteed recovery of the costs associated with unit startup and no-load costs. To the extent these costs are not recovered from energy markets during each day, PJM pays these units the difference between their operating costs and revenues for the day. These uplift costs were collected from PJM customers through an operating-reserve payment, although the nexus between these costs and reserves is ambiguous.

Since December 1, 2002, PJM (2002) has operated a two-tier market for spinning reserve; PJM does not yet operate markets for supplemental or replacement reserves. FERC (2002b) approved the PJM market, noting, however, that it "does not contain all the attributes contemplated by the Commission in the SMD NOPR, and the PJM proposal is different from the spinning reserve markets in New York and New England."

[9] The price of spinning reserve in New York may be slightly higher because this number does not include the opportunity-cost payments the ISO makes to generators that are dispatched below their economic point to provide spinning reserve

Tier 1 of the spinning reserve market consists of units that are online, following economic dispatch, and able to ramp up in response to a contingency. These units do not receive an upfront reservation payment, although they do receive an extra $50-100/MWh for energy produced during a DCS event. Tier 2 consists of additional capacity synchronized to the grid, including condensing units, that can provide spinning reserve.[10] These units are paid a reservation charge, based on a real-time market-clearing price but receive no extra energy payment during a reserve pickup.

The PJM markets for spinning reserve appear to be aimed at particular kinds of generating units, perhaps in recognition of the fleet of generators within its control area. As a consequence, the market design is not well-suited for demand resources because there is no way for retail loads to participate in these markets.

Technical Requirements to Provide Contingency Reserves

ISOs impose various performance, metering, and communication requirements on resources that provide contingency reserves. These technical requirements were typically developed with large generators in mind. Thus, a fundamental challenge is to encourage regional reliability councils and ISOs/RTOs to think more broadly about the resources that can provide reliability services to accommodate participation by customer loads, how to value and pay for the reliability services these resources provide, and how to cost-effectively deploy such resources.

For example, in terms of performance, contingency reserve resources must demonstrate the claimed ramping capability (in MW/minutes) so the ISO can be confident that, during an emergency, the resource will be able to respond as rapidly as required so the ISO can meet DCS. The resource must also sustain the committed output for a minimum amount of time, typically an hour or more, and must then be able to ramp down within a specified time to its pre-contingency level so that it is positioned to respond to another outage (see Table 2).

Because the time between a major outage and full recovery is so short (15 minutes), the system operator requires close communications and frequent updates on the status of the resources providing contingency reserves. During an emergency, the ISO must be able to send its request for increased output (or reduced load) to participating resources quickly, and the system operator requires the resources to confirm receipt of the dispatch order rapidly. Traditionally, generators that provide contingency reserves measure and report their output to the system operator once every several seconds. Thus, these units have sophisticated and expensive metering and telecommunications systems. In addition, the system operator requires the units to have telephone (or other voice) communication links with the control center.

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[10] A combustion turbine capable of connecting to the grid and spinning the generator without burning fuel is one type of synchronous condenser (PJM 2002).

Customer Load as Reliability Resource: Characteristics and Challenges

At present, no retail loads provide reserve services in any of the three Northeastern ISOs (PJM, New York, or New England), perhaps because of these extensive and expensive technical requirements. A few large customer loads (large water-pumping loads) provide reserves in the California ISO's (CAISO) Participating Load program. The CAISO adopted the concept of an Aggregating Load Meter Data Server, a data-acquisition and processing system that collects data from individual loads and passes the aggregate data to the ISO's computer system. Although the data server is required to send data to the ISO every four seconds for supplemental reserve and once a minute for replacement reserve, the individual loads report data to the data server at one-minute intervals for supplemental reserve and once every five minutes for replacement reserves.[11]

However, many different types of loads can potentially supply contingency reserves to the power system. Loads that are potentially good candidates to provide these services would share common characteristics. These characteristics include:

1. loads that have storage involved in its process or processes that can add storage (e.g., thermal storage such as water heating and heating/cooling, process inventory, compressed air, and water pumping),
2. control capability,
3. loads that require little or no advanced notification, rapid response to curtail (including communications time),
4. ability to quickly restore load,
5. sufficient aggregate size, and
6. loads with acceptable standby and deployment costs.

For example, households with electric water heaters are unlikely to notice any performance degradation (e.g., lukewarm water) if the duration of the interruption is short (e.g., less than an hour). Water heaters can also be turned back on again very quickly, and be ready, once again, to provide contingency reserves.

Typically, DCS events occur rarely, roughly once a month.[12] Thus, a retail load selling reserves could expect an occasional interruption and can count on a modest reservation (capacity) payment hour after hour. Viewed in this light, the desirable demand characteristics might be

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[11] We are unable to identify the benefits associated with provision of partial data to the CAISO every four seconds if the underlying loads provide data only once every one or five minutes. Also, it is not clear whether this California approach reduces metering and communications costs enough to entice otherwise eligible loads to participate in the markets for contingency reserves.

[12] New England has averaged 14 DCS events a year during the past five years (12 in 1998, 10 in 1999, 15 in 2000, 19 in 2001, and 10 during the first three quarters of 2002). This is about the same rate experienced in New York and PJM.

driven as much by financial and convenience considerations as by physical characteristics of the load, i.e., the willingness to adjust to an occasional curtailment in exchange for a steady revenue stream.

However, the existing technical and performance requirements, which were designed with generators in mind, create a significant challenge for loads to participate. An alternative way to view demand-side provision of contingency reserves is to ask what the system operator really needs to maintain reliability rather than just accept the current rules. Conceivably, a more flexible set of performance-based requirements would likely encourage demand participation and improve reliability. For example, to what extent do these requirements make sense for individual and aggregated resources provided by customer loads? There is no reason why an *individual* resource must maintain its emergency output or load reduction for the 60 minutes specified by NPCC. DCS performance could be just as good if some loads responded immediately and were then replaced by other load reductions after, say, 30 minutes. With this simple modification to the NPCC requirements, loads that can interrupt for 30 minutes, but not for 60 minutes, would be able to provide contingency reserves.[13]

Table 3 provides an overview of the characteristics of loads and some key program design feature that should be considered if loads are to provide contingency reserves.

Table 3. Characteristics and proposed requirements for load participation in contingency-reserve markets

	Spinning reserve	Supplemental reserve	Replacement reserve
Aggregation	Specify minimum resource size (e.g., 1 MW); allow aggregation and sampling of small loads to infer performance for total population		
Metering	Sufficient data to measure performance of individual resources; interval meters capable of recording consumption at 1-, 5-, and 10-minute levels for large loads		
Communication	Daily submission (or standing offers) of hourly capacity and energy bids to RTO; RTO calls winning bids to curtail loads within required times		

13 However, the 60-minute requirement would reduce by 50% the amount of contingency reserves provided by loads relative to a 30-minute requirement for sustained output.

Response time	10 minutes	30 minutes
Frequency	Voluntary customer participation; customer load commits to provide contingency reserve service if ISO selects and schedules their day-ahead bid to sell reserves during certain hours	
Duration	30 to 60 minutes	
Penalties	Penalties applied because load committed to make reductions upon RTO call for reliability service (quid pro quo for reservation payment)	
Payments	Day-ahead hourly market clearing prices for capacity and energy bid	
Baseline	Baseline consumption based on one or a few intervals before the ISO call because of short advance notice	

II. Recommendations

Retail loads have the potential to make a substantial contribution to contingency reserves. Modifying the reliability requirements to accommodate demand resources and including demand resources in revised markets will improve the efficiency of wholesale energy, ancillary-service, and congestion-management markets. NEDRI participants offer the following recommendations to facilitate customer load participation in contingency reserve markets.

Recommendation 1: ISO New England (ISO-NE) should design and implement markets for all three contingency reserve services as soon as possible.

We recommend that ISO-NE New England develop and implement contingency reserve markets that follow closely FERC's SMD proposal. ISO-NE should consider adopting a day-ahead market design that integrates availability bids for the reserve services with energy bids and integrates reserves and energy in real time. Such an integrated system will ensure that reserve prices fully reflect their value, especially during periods of scarcity (Patton 2002). Loads would participate in the day-ahead reserve markets by submitting availability bids (in $/MW-hr) and the energy strike price (in $/MWh) above which they would be willing to interrupt some load. Accepted load and generator bids would be treated the same way; in the event of a major outage, the ISO would dispatch generators and loads in economic merit order. Loads and generators that failed to respond to the ISO's dispatch signal during a DCS event would face the same nonperformance penalties.

- **Recommendation 2: ISO-NE, working with the Northeast Power Coordinating Council (NPCC), should ensure that the reliability rules and requirements related to DCS and contingency reserves are technology- neutral and performance-based. NPCC should publish engineering/economic analyses used to justify reliability rules.**

The NPCC contingency reserve requirements were designed to accommodate typical generating units and are not necessarily well-suited for demand resources that might fully satisfy appropriate reliability requirements. Longer duration for reserves may improve reliability but it also raises costs and limits the number and type of resources that can provide reserves. Reliability rules should also recognize the technical differences between reserves provided by large resources (whose expected performance is generally deterministic) and small resources (whose expected performance can be derived from statistical approaches).

The rules should also accommodate resources whose availability and size varies, especially for those resources where the variability is positively correlated with system load (in particular, weather-sensitive loads). These rules should address the reliability requirements associated with speed of response, duration of response, and speed of restoration. For example, some retail loads with modest amounts of storage (e.g., residential electric water heaters) can be interrupted very quickly (within seconds of notification) but can conveniently sustain the interruption for only short periods (e.g., less than one hour). Options that should be considered included allowing resources with shorter minimum sustainable time to provide contingency reserves using more sophisticated resource deployment strategies (e.g., dispatch one set of electric water heaters when the outage occurs and a second set 30 minutes later when the first set is restored to normal operation).

Recommendation 3: ISO New England should review its contingency reserve metering and communications requirements and consider less frequent (and costly) data recording and reporting requirements for loads; any revision of these requirements must be contingent on the continued maintenance of reliability requirements.

ISO-NE should review the requirements it imposes on resources that provide contingency reserves with respect to the frequency of metering output (or consumption) and the frequency with which these MW values are communicated to the ISO's control center. The 4-second recording and reporting requirement imposed on generators is probably not needed for retail loads that provide contingency reserves, primarily because of the much smaller size of these demand resources. It may be sufficient for large loads to record load data at the 1- or 5-minute level for 10-minute reserves and the 5- or 10-minute level for 30-minute reserve. For small load resources (e.g., residential water heaters), sampling approaches should be considered, where a representative sample of loads are metered and results are then scaled up to the population of participating loads. In both cases, there may be no reliability reason to report performance results to the ISO in near real-time; it may be sufficient to provide such data at the end of each month for billing and settlement purposes. Revised data recording and reporting protocols would necessarily have to be integrated within ISO New England's Energy Management System.

Recommendation 4: There should be a market potential study and pilot demonstrations that assess the benefits and costs of using large and small loads to provide contingency reserves. The pilot demonstrations should be reflective of the actual system logistics involved in aggregating and incorporating numerous small load resources. As part of the pilot, load research protocols for aggregations of small loads should be developed and evaluated, which may serve as an equivalent alternative to traditional performance measurements used for generators. Candidate sponsors to conduct these studies and pilot demonstrations include US DOE, ISO-New England, and New England utilities.

Given limited participation by loads in contingency reserves markets, demonstration pilots are needed to overcome technical and market barrier, assess costs and benefits under varying metering and communications requirements, and work with ISO system operators to accommodate customer load participation while meeting ISO system reliability needs. Such pilot demonstrations could involve a few large industrial loads and an aggregation of residential loads (perhaps through a utility’s existing direct-load-control program). A market potential study would examine opportunities in the residential, commercial, and industrial sectors to see which customers and which end uses are most suitable for the provision of contingency reserves. The study would characterize customer loads based on their seasonal characteristics, storage capabilities, the speed with which they can be interrupted and rearmed (restored), and the costs of the necessary metering and communications equipment. The resultant estimates of resource potential will be a function of reliability and market rules as well as the payments to retail loads for provision of reserve services.

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