OPPORTUNITIES FOR DEMAND PARTICIPATION IN NEW ENGLAND CONTINGENCY-RESERVE MARKETS

Eric Hirst and Brendan Kirby??
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1. INTRODUCTION

The Federal Energy Regulatory Commission (FERC 2002a), in its notice on Standard Market Design (SMD), is clear that it wants loads to participate in wholesale power markets and much prefers this to special load-reduction programs: "We believe the direct approach of letting demand bid in the market will be less costly than a program where an end-user receives payments greater than the market clearing price to reduce its demand."

To date, however, the primary mechanism through which retail loads respond to wholesale prices and reliability concerns is via special demand-response programs, not the existing markets for energy, congestion management, and ancillary services. Nevertheless, direct participation of retail loads in wholesale power markets is likely to expand the scope of these markets, lower prices (especially price spikes), reduce the opportunities for the exercise of market power, and improve reliability. 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 paper deals with the issues and opportunities New England faces in getting retail loads to provide some of the real-power ancillary services and to participate in the markets for these services. The paper focuses on the three contingency reserves that are deployed throughout the Northeast: 10-minute spinning reserve, 10-minute nonspinning (supplemental) reserve, and 30-minute (replacement) reserve. The paper explains what these services are, the technical and reliability requirements imposed on resources that provide

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[1]Eric Hirst is a Consultant in Electric-Industry Restructuring in Bellingham, WA. Brendan Kirby is a senior researcher at Oak Ridge National Laboratory in Oak Ridge, TN. The work reported here was coordinated by the Consortium for Electric Reliability Technology Solutions and funded by the Assistant Secretary for Energy Efficiency and Renewable Energy, U.S. Department of Energy, under Contract No. DE-AC03-76SF00098 with Lawrence Berkeley National Laboratory and Contract No. DE-AC05-00OR22725 with Oak Ridge National Laboratory.

these services, the design and results of markets for contingency reserves, the desirable characteristics of retail loads that might provide reserves, and recommendations to NEDRI and ISO New England to encourage demand participation in reserve markets.

2. 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 redispatch generation (or load) to manage power flows through individual transmission facilities. Table 1 lists the key real-power ancillary services, the ones that ISOs generally buy in competitive markets.

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's 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's 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 precontingency 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. The regulation ancillary service is the primary resource system operators use to meet CPS. In principle, customer loads could provide the service as well as generators. Because provision of this 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. Therefore, this paper does not discuss load provision of regulation.

The three contingency-reserve services are all used to help control-area operators meet the DCS (Table 1). Briefly, DCS requires that the system recovers from a major outage within 15 minutes,[??] with a major outage defined as one between 80 and 100% of the largest single contingency. The three reserve services provide responses of different quality. 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. 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. Supplemental reserve, which could include generators that are already online, is less valuable because it does not necessarily provide an *immediate* response to an outage. Both spinning and supplemental reserves must reach their committed output within 10 minutes of being called on by the system operator. Replacement reserve is less valuable still because it need not respond fully until 30 minutes after being deployed. Replacement reserves are used to permit the restoration of the 10-minute reserves so that these faster-acting resources are, once again, able to respond to a new emergency.

NERC's DCS is a performance measure;[03] it specifies what must be accomplished (recovery within 15 minutes) without specifying how that goal must be reached.[§] The *Operating Reserve Criteria* of the Northeast Power Coordinating Council (NPCC 2002), on the other hand, is 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. Further, NPCC 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.

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[1]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.

[2]Policy 1 requires 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."

[3]Until November 2002, NERC's Policy 1 was prescriptive. NERC required that, with some exceptions, at least 50% of the 10-minute reserves be spinning. Perhaps more important, NERC restricted spinning reserve to "unloaded generation that is synchronized and ready to serve additional demand." Clearly, this statement excluded customer loads from providing this valuable ancillary service. NERC's new Policy 1 permits contingency reserves to be "supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules," a very important change for demand resources.

ISO New England typically acquires about 600 to 700 MW each of spinning reserve, supplemental reserve, and replacement reserve.[??] 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; for example, 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

[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.

3. TECHNICAL REQUIREMENTS TO PROVIDE RESERVES

The ISOs impose various performance, metering, and communication requirements on resources that provide contingency reserves. In terms of performance, the resource 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. In addition, the resource must be able to sustain the committed output for

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[1]In May 2002, the ISO 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.

a minimum amount of time, typically an hour or more, and must then be able to ramp down within a specified time to its precontingency level so that it is positioned to respond to another outage (restoration); 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, the generators providing 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.

These technical requirements were all developed with large generators in mind. To what extent do these requirements make sense for individual and aggregated demand resources? That is, what does the system operator need to know about these resources, which on average, are much smaller than the typical generator, and how frequently must this information be updated? How much can retail loads afford to spend on metering and communications, given the likely market payments for reserves of only a few dollars per megawatt per hour (see next section)?

Perhaps because of these extensive and expensive technical requirements, no retail loads provide reserve services in any of the three Northeastern ISOs (PJM, New York, or New England). Only in California do some retail loads (large water-pumping loads, to be specific) provide reserves. The California ISO 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 reserve.[??] However, the underlying questions remain: How often does the system operator need to know how individual resources are performing in their provision of contingency reserves? How does the frequency with which this information is sent to the system operator depend on whether the resource in question is a large generator or the aggregation of many small loads?

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[1]We are unable to identify the benefits associated with provision of partial data to the ISO 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.

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., about an hour).[03] Should such resources be prohibited from providing contingency reserves because of requirements developed with generators—and only generators—in mind? Consider the possibility of allowing resources with shorter minimum sustainable time to provide reserves (which would accommodate loads with limited storage) and more sophisticated resource deployment (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). The fundamental issue here is how to get the regional reliability councils and the ISOs/RTOs to think more broadly about the resources that can provide reliability services, how to value and pay for the reliability services these resources provide, and how to cost-effectively deploy such resources.

4. MARKETS FOR CONTINGENCY RESERVES

NEW ENGLAND

Since ISO New England began operating real-time markets for energy and ancillary services in May 1999, it has experienced problems with its markets for the reserve services. Complications in the design of the ISO'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 (1999) filed emergency market revisions with FERC. The ISO noted that its first three months of operation had led it to

> conclude that four of the [ISO] markets, ten-minute nonspinning 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 the market 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

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[1]Many electric utilities operated (and some continue to run) direct-load-control programs that automatically cycled or turned off individual household appliances, such as water heaters, air conditioners, heating systems, or swimming-pool pumps. Although these programs were generally not used to provide contingency reserves, they provide a wealth of useful information on how to market such programs to customers and their performance.

the hope there is any positive price) or a bid that is an attempt to set the clearing price.

In response to the ISO's request, FERC (1999) permitted the ISO to cap the prices of operating reserves at the current hour's energy price. This authority, however, was limited to special circumstance. FERC noted that "… bid caps in the operating reserve markets are limited to periods of capacity deficiency [OP4] or system emergency [OP8] when the ISO is required to choose all bids regardless of how high the price might be. … until this flaw is remedied by an alternative market design, the risk of arbitrarily high prices will remain."

The prices paid by ISO New England for reserves may have little meaning because of flaws in the ISO's reserve markets. During the past three years, prices have been consistently below $2/MW-hr.[??] During the 3-year period from January 2000 through December 2002, the price of spinning reserve averaged $1.15, the price of supplemental reserve averaged $2.08, and the price of replacement reserve averaged $0.81/MW-hr. (During 2002, the prices averaged $1.68, $1.67, and $1.10/MW-hr, respectively). The annual cost of the three reserve services was $30 million in 2002.

New England will implement a new, improved market design in March 2003, based on the design now operating in PJM. This new market system, however, will not include PJM's two-part market for spinning reserve (see discussion below) (Pattton 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 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.

Prices in the New York ISO ancillary-service markets, which do not contain the flaws that the New England markets have, might be a more reasonable indicator of what prices should be in a well-functioning market. New York, like New England, acquires roughly 600 MW of each of the three reserve services each hour. For the 2-year period from January 2001 through December 2002, the prices of spinning, supplemental, and replacement reserve in

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[1]MW-hr refers to a megawatt of ancillary service provided for one hour, different from a MWh of energy.

New York averaged 2.74,[03] 1.69, and $1.16/MW-hr, respectively. This ordering of prices is consistent with the value of each service, with spinning reserve the most valuable and replacement reserve the least valuable. (The New England prices, on average, did not follow this order.) New York spent $29 million on contingency reserves during 2002, almost exactly as much as did New England.

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 noload 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.

Beginning on December 1, 2002, PJM (2002) began operating a two-tier market for spinning reserve. (PJM does not yet operate markets for the other contingency reserves.) Tier 1 consists of units online, following economic dispatch, and able to ramp up in response to a contingency. These units receive no upfront reservation payment but do receive an extra $50 to $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.[??] 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.[03] PJM does not 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."

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 hostile to demand resources in that there is no way for retail loads to participate in these markets.

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[1]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.

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

[3]It is baffling that a *competitive* market would be designed to pay resources providing the identical service different amounts, and in different ways, based solely on the cost to the resource of providing the service.

FERC

FERC's (2002a) proposed SMD requires day-ahead markets for spinning and supplemental reserves, but not for the 30-minute replacement reserve. These markets are to be integrated with the energy market, much as New York does. This integration 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, much as New York proposes in its Real-Time Scheduling system. 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. FERC is clear that it wants these ancillary-service markets to be open to demand-side resources as well as generators.

5. DESIRABLE DEMAND CHARACTERISTICS[??]

In the first instance, the characteristics required of contingency reserves, as determined by NERC and the regional reliability councils (e.g., Table 2), should determine the desirable attributes of the demand resources that might provide these services. Ideally, the participating retail load should be able to be interrupted *immediately*,[03] sustain the interruption for the amount of time required by the regional reliability council (e.g., one hour), return to full load within the time required by the regional reliability council for restoration (e.g., within 90 to 105 minutes after the contingency occurred), and then be ready to be interrupted again.

The reality is that DCS events occur rarely, roughly once a month.[§] Thus, a retail load selling reserves can count on a modest reservation (capacity) payment hour after hour

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[1]See Kirby and Hirst (2003) for additional detail on demand characteristics for reserve provision.

[2]NERC's earlier Policy 1, while it required spinning-reserve resources to respond immediately, provided no definition of immediately. NERC's (2001) proposed Frequency Response Standard calls for the response to begin within 10 seconds and be completed within one minute.

[3]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.

and only an occasional interruption.[†] Viewed in this light, the desirable demand characteristics might be driven as much by financial and convenience considerations as by physical characteristics, i.e., the willingness to adjust to an occasional curtailment in exchange for a steady revenue stream.

Some industrial loads (such as a production line) might be able to shut down in response to an emergency on the electrical system. The high cost of shutting down and restarting an entire production process suggests that such a resource might be called upon only when the interruption is long (e.g., a full 8-hour shift). Such a large industrial load, therefore, is quite different from residential water heaters. 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). In addition, water heaters can be turned back on again very quickly, and be ready, once again, to provide contingency reserves. Other resources take much longer to be restored and rearmed to provide reserves. Thus, different retail loads are well suited to provide different services to the bulk electric system.

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. After all, the current rules were designed to accommodate large generating units, not demand resources. A more flexible set of performance-based requirements would likely encourage demand participation and improve reliability. For example, 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. (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.) Such a rule change would expand the amount of resources that could participate in ISO contingency-reserve markets, thereby improving reliability and reducing the costs of doing so.

Table 3 summarizes the characteristics loads must meet to provide contingency reserves (Hirst 2002).

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[1]We assume here that retail loads will be paid for reserves just as generators are. They will receive an hourly reservation payment based on the price set in the day-ahead market and, when called upon to reduce load, they will enjoy the benefit of a lower energy payment during this time of higher energy prices. That is, loads would not receive an additional energy payment for interrupting during a DCS event.

Table 3. Characteristics of load participation in contingency-reserve markets

	Spinning reserve	Supplemental reserve	Replacement reserve
Aggregation	RTO might require minimum size, say 1 MW, which would require aggregation for all but the larger industrial loads		
Meters	Sufficient data to measure performance of individual resources[a]		
Communication	Daily submission (or standing offers) of hourly capacity and energy bids to RTO, RTO must be able to call on winning bids to reduce loads within required times		
Response time	10 minutes		30 minutes
Frequency	Customers are free to participate in these markets as they choose; once having chosen on a day-ahead basis to sell reserves during certain hours, they are then committed to providing that service if called upon		
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 plus savings based on actual load reductions when called upon[b]		
Baseline	Because advance notice is so short, baseline can be consumption during one or a few intervals before the ISO call		

[a]Performance monitoring for large loads might include interval meters capable of recording consumption at the 1-, 5-, or 10-minute level. For small loads, it should be sufficient to carefully monitor the performance of only a small, suitably chosen sample of loads and use these results to infer performance for the total population of participating loads. Data on the performance of the on:off switches for, say water heaters, would also be valuable here.

[b]Loads participating in the reserve markets would not receive a separate payment for the energy they did not consume during a DCS event.

6. RECOMMENDATIONS TO NEDRI AND ISO NEW ENGLAND

The potential for retail loads to be an important contributor to contingency reserves is substantial. 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. By accommodate, we do not mean preferential treatment for one class of resources. Rather, we mean broad consideration of the economic benefits and costs of modifying reliability rules to expand the scope and scale of resources that are allowed to provide reliability services.

We encourage the NEDRI participants to consider the following recommendations for ISO New England, NPCC, and FERC:

- ISO New England should, as soon as possible, design and open markets for all three continency-reserve services. Without functioning markets for the reserves, it is difficult to see how retail loads could provide—and be compensated fairly for— these services.

  We recommend that New England not adopt PJM's two-part market for spinning reserve for two reasons. First, the PJM markets were designed for the particular kinds of generating within its control area and are not amenable to load participation. Second, PJM has no markets for supplemental and replacement reserves. Rather, New England should implement markets that follow closely FERC's SMD proposal, as exemplified by the New York markets. In particular, ISO New England should adopt 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.

- ISO New England should continue to work with NPCC to ensure that the reliability rules and requirements related to DCS and contingency reserves are truly technology neutral. In addition, NPCC and ISO New England should publish the results of the engineering and economic analyses used to justify these standards and rules.

The NPCC requirements (Table 2) were designed to accommodate typical generating units and are likely unsuitable for demand resources that might fully satisfy appropriate reliability requirements. For example, NPCC offers no explanation or justification for the 60-minute minimum duration of reserves.[??] Longer duration may improve reliability but it also raises costs and limits the number and type of resources that can provide reserves. Where, one might ask, are the data and analysis showing the economic costs and benefits of different duration times (as well as the other parameters shown in Table 2)? The rules should recognize the technical differences between reserves provided by large resources (whose expected performance is generally deterministic) and small resources (whose expected performance is generally statistical). 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.

- ISO New England 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 and then report results to the ISO at the end of each month for verification and billing purposes. For small load resources (e.g., residential water heaters), it should be sufficient to carefully meter only a small fraction of the loads and then scale up to the population of participating loads.[03] In both cases, there may be no reliability reason to report performance results to the ISO

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[1]NPCC prepared a study in October 2002, "Estimating the Reliability Impact of Extending the Ten Minute Reserve Restoration Period From Thirty to One Hundred Five Minutes." The study, for security reasons, is not posted on the NPCC website and is not publicly available. Perhaps more important, this study is largely theoretical; it does not use data on the size, frequency, and timing of large outages in the Northeast.

[2]In response to intervener comments concerning the requirement for interval meters to measure demand curtailments, FERC (2002c) ordered NEPOOL and ISO New England "to work with interested parties … to develop performance-based, rather than technology-based, standards for determining energy usage [and load reductions]."

in near realtime; it may be sufficient to provide such data at the end of each month for billing and settlement purposes.

- NEDRI, ISO New England, distribution utilities, and state energy offices and PUCs should work together to characterize the potential demand resource for reserves in New England.

  This assessment would examine opportunities in the residential, commercial, and industrial sectors to see which customers and which end uses are suitable for the provision of contingency reserves. This characterization will examine the seasonal characteristics of different loads, their storage capabilities, the speed with which the load 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.

- NEDRI, ISO New England, distribution utilities, and state energy offices and PUCs should encourage loads to provide contingency reserves and to participate in the ISO markets for these reserve services.

  To stimulate such participation, the ISO should work with LSEs and other load aggregators to combine many small loads. Such aggregation should improve greatly the economics of load participation in these markets. The ISO could, based on the prior recommendation, work with the load aggregators to develop metering and communication requirements that meet the ISO's legitimate reliability needs and accommodate the needs of the load aggregators and individual retail customers. The ISO recently organized a Demand Response Measurement Working Group to develop performance-based measures of demand response, i.e., alternatives to the metering and communications requirements currently required in the ISO's demand-response programs. In addition, the ISO and LSEs should educate customers on bulk-power reliability issues, the importance of contingency reserves, and the role that demand resources can play in cost-effectively providing these reserves. Finally, the ISO might establish a pilot program to demonstrate the market barriers, and benefits and costs of using large and small loads to provide contingency reserves. Such a pilot program could involve a few large industrial loads and an aggregation of residential loads (perhaps through a utility's existing direct-load-control program).

- The ISO should, working with LSEs and others, design load-research protocols that could be used when reserves are provided by aggregations of many small loads and which could substitute for the traditional performance measurement used for generators. Such protocols would measure the load-reductions of various types of loads under different conditions (time of day, day of the week, and season, as examples) and develop methods to forecast expected load reductions from different types of loads participating in contingency-reserve markets. The recently-organized ISO working group mentioned above will address these issues also.

- Finally, ISO New England should encourage FERC to be sure that the regional reliability councils (including NPCC) continue to review and modify their reliability rules (Operating Reserve Criteria, in the NPCC case) so they are performance-based, technology neutral, and consistent with FERC’s proposed SMD.

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